Exhibit 81

Anadarko Announces Another Deepwater Gulf of Mexico Discovery

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HOUSTON - (BUSINESS WIRE) - Anadarko Petroleum Corporation (NYSE:APC) today announced its second deepwater Gulf of Mexico discovery this week. The Shenandoah discovery well, located in Walker Ridge block 52, encountered net oil pay approaching 300 feet in the Wilcox formation.

“This has been a remarkable week, with back-to-back deepwater discoveries in the Gulf of Mexico,” said Bob Daniels, Anadarko Sr. Vice President, Worldwide Exploration. “Initial data indicates the Shenandoah discovery has reservoir properties that appear to be of much higher quality than industry has seen previously in the emerging Lower-Tertiary play. The success of this well and our recent Heidelberg discovery further confirms the value of Anadarko’s extensive acreage position and our capability in exploring proven and emerging deepwater basins worldwide.”

Shenandoah is located in approximately 5,750 feet of water and was drilled to a total depth of about 30,000 feet. Anadarko and the co-owners of the discovery are evaluating the well results and the next steps toward future appraisal activity. Anadarko operates Shenandoah with a 30-percent working interest. Co-owners of the discovery include ConocoPhillips (40-percent working interest), Cobalt International Energy, L.P. (20-percent working interest) and Marathon (10-percent working interest).

Also in the deepwater Gulf of Mexico, Anadarko expects to spud the Vito Middle-Miocene prospect in Mississippi Canyon block 984 and the Samurai Middle- and Lower-Miocene exploration well in Green Canyon block 432 during the first quarter. Anadarko operates these wells with a 20-percent working interest and a 33.33-percent working interest, respectively.

A map of the Shenandoah discovery and Anadarko’s additional Lower-Tertiary exploration opportunities in the area is provided under the “Media Center/Anadarko News” tabs at www.anadarko.com.

Anadarko Petroleum Corporation’s mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world’s health and welfare. For more information about Anadarko, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including our ability to successfully drill, complete, test and produce the wells described in this release. See “Risk Factors” in the company’s 2007 Annual Report on Form 10-K and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

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Exhibit 82

Anadarko Petroleum Corporation

NEWS

ANADARKO ANNOUNCES SHENANDOAH APPRAISAL WELL ENCOUNTERS MORE THAN 1,000 NET FEET OF OIL PAY

HOUSTON, March 19, 2013 – Anadarko Petroleum Corporation (NYSE: APC) today announced its Shenandoah-2 well in the deepwater Gulf of Mexico encountered more than 1,000 net feet of oil pay in multiple high-quality Lower Tertiary-aged reservoirs.

"The successful Shenandoah-2 well marks one of Anadarko's largest oil discoveries in the Gulf of Mexico, with more than 1,000 net feet of oil pay and reservoir rock and fluid properties of much higher quality than previously encountered by industry in Lower Tertiary discoveries," said Bob Daniels, Anadarko Sr. Vice President Deepwater and International Exploration. "With ownership in the successful Shenandoah wells, the adjacent Yucatan prospect, and the very encouraging results from the nearby Coronado well, Anadarko is strategically positioned in the Shenandoah Basin, which has the potential to become one of the most prolific new areas in the deepwater Gulf of Mexico."

The Shenandoah-2 well, located in Walker Ridge block 51, was drilled to a total depth of 31,405 feet in approximately 5,800 feet of water, more than 1 mile southwest and approximately 1,700 feet structurally down-dip from the Shenandoah-1 discovery. Similar to the initial Shenandoah discovery well, log and pressure data from the Shenandoah-2 well indicate excellent-quality reservoir and fluid properties. The well was drilled to test the down-dip extent of the accumulation, and the targeted sands were full to base with no oil-water contact.

"We are incorporating the information obtained from Shenandoah-2 into our planning and anticipate further appraisal drilling to advance this potentially giant project," Daniels added.

Anadarko is the operator of the Shenandoah-2 well and the previously announced Shenandoah-1 discovery well, located in Walker Ridge block 52, with a 30-percent working interest. Other co-owners in Shenandoah are ConocoPhillips (NYSE: COP) with a 30-percent working interest, Cobalt International Energy L.P. (NYSE: CIE) with a 20-percent working interest, Venari Resources LLC with a 10-percent working interest and Marathon Oil Company (NYSE: MRO) with a 10-percent working interest.

Additionally, in the Shenandoah Basin, Anadarko has a 15-percent working interest in both the Coronado well, located in Walker Ridge block 98, and the Yucatan prospect, located in Walker Ridge block 95.

A map of the Shenandoah Basin in the deepwater Gulf of Mexico will be available under the "Media Center/Anadarko News" tab at www.anadarko.com.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2012, the company had approximately 2.56 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and APC Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to successfully drill, complete, test and produce the wells and prospects identified in this news release. See "Risk Factors" in the company's 2012 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

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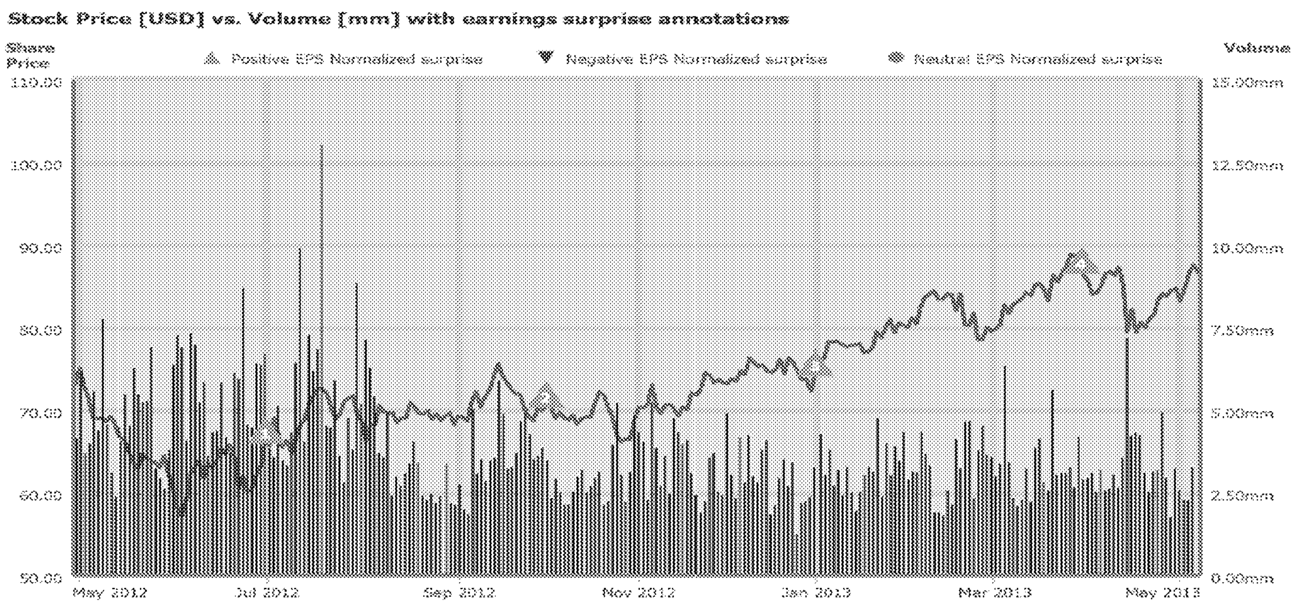
Exhibit 83

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
FQ1 2013 Earnings Call Transcripts
Tuesday, May 07, 2013 2:00 PM GMT
S&P Global Market Intelligence Estimates

	-FQ1 2013-			-FQ2 2013-	-FY 2013-	-FY 2014-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	0.94	1.08	▲14.89	0.86	4.18	5.31
Revenue (mm)	3436.98	3893.00	▲13.27	3427.44	15198.01	16959.98

Currency: USD
Consensus as of May-07-2013 1:15 PM GMT



	- EPS NORMALIZED -		
	CONSENSUS	ACTUAL	SURPRISE
FQ2 2012	0.77	0.85	▲10.39 %
FQ3 2012	0.77	0.84	▲9.09 %
FQ4 2012	0.72	0.91	▲26.39 %
FQ1 2013	0.94	1.08	▲14.89 %

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EXECUTIVES

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Charles A. Meloy
Former Executive Vice President

John M. Colglazier
Investor Relations Professional

R. A. Walker
Chairman & CEO

Robert Douglas Lawler
Former Senior Vice President of International & Deepwater Operations

Robert G. Gwin
President

Robert K. Reeves
Former Executive VP & Chief Administrative Officer

Robert P. Daniels
Former Executive Vice President

ANALYSTS

Arun Jayaram
Crédit Suisse AG, Research Division

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

David William Kistler
Simmons & Company International, Research Division

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

Joseph Patrick Magner
Macquarie Research

Ross Payne
Wells Fargo Securities, LLC, Research Division

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Unknown Analyst

Presentation

Operator

Good morning. My name is Steve, and I will be your conference operator today. At this time, I would like to welcome everyone to the Q1 Anadarko Petroleum Corporation Earnings Conference Call. [Operator Instructions] Thank you. I would now like to turn the conference over to your host for today, John Colglazier. Please go ahead, sir.

John M. Colglazier
Investor Relations Professional

Thanks, Steve. Good morning, everyone. We're glad you could join us today for Anadarko's First Quarter 2013 Conference Call. Today's presentation includes forward-looking statements and certain non-GAAP financial measures. A number of factors could cause actual results to differ materially from what we discuss today. We encourage you to read our full disclosure on forward-looking statements and GAAP reconciliations located on our website and attached to last night's earnings release. Also on our website, we provide a comprehensive summary of our global activities in our quarterly operations report. In a moment, we'll turn the call over to Al Walker, who will discuss the company's first quarter results. Al will be joined by certain members of our executive team who will be available to answer questions later in the call. With that, go ahead, Al.

R. A. Walker
Chairman & CEO

Thanks, John. We appreciate everyone taking the time to be with us today. We felt we had an outstanding first quarter, and 2013 is shaping up to be the breakout year for Anadarko that we've talked about. To highlight this, we achieved record sales volumes in Q1. This was led by 16% year-over-year increase in oil sales per day. We announced new monetizations, which exceeded $1.2 billion during the quarter. The most significant was the $860 million deal for Heidelberg. This further enhanced our use of capital in a very tax-efficient manner. We announced the new GOM exploration success, including one of the biggest deepwater oil discoveries in our company's history, and we achieved first oil at the El Merk development in Algeria. And importantly, we generated very strong cash flow and further strengthened the balance sheet.

Our U.S. onshore plays were major contributors to the company's strong first quarter performance, achieving record sales of 565,000 BOE per day, representing a 16% growth versus Q1 '12, and this was against the headwind of ethane rejection, which took away more than 10,000 barrels a day of production.

Before we highlight the strong operating performance we achieved in the Wattenberg and Eagleford, it's worth taking a moment to note the attractive pricing and value we received again this quarter for our crude oil volumes. Our domestic crude oil continues to enjoy a premium pricing relative to WTI due to the fact that most of our production is waterborne benchmarked and the majority of our U.S. onshore production is light to medium quality. And as you can see in the graphic, it's limited in terms of the gas condensate production we actually realized.

The value uplift is clear, as our overall average price is almost $103 per barrel, or $8.60 in average premium to the WTI over the period. The Wattenberg Field continues to be a top performer. Our sales volumes were enhanced by liquids increase of 45% year-over-year. To accelerate value, we tripled the number of horizontal wells drilled in the first quarter of 2013, and we expect to increase this over the course of next year and this year. This asset enjoys the strongest return on capital characteristics in our portfolio, with an expected rate of return exceeding 100%.

The Eagleford Shale is also delivering exceptional results. Total liquids for the quarter increased approximately 60% over the same period in 2012, and we are expanding our takeaway capacity with a 200-million-a-day gas processing plant, which will increase our throughput and yields from the liquids and should come online in the second quarter.

The U.S. onshore is complemented by the advancing development of our global projects. During the quarter, Anadarko and Sonatrach initiated oil production at the El Merk complex in Algeria, where we expect oil volumes throughout the year to build to an exit rate of around 30,000 barrels per day net to Anadarko, as 2 facilities and 3 additional fields are brought online.

In Ghana, gross daily production has averaged 104,000 barrels of oil per day year-to-date, and an expansion of the gas handling capacity at the FPO to enable higher oil volumes is being planned. And we're working with the government, advancing the TEN project.

The Gulf of Mexico developments include the Lucius spar, which recently set sail on schedule from the fabrication yard in Finland for the Gulf of Mexico, and it's 80,000-barrel-a-day twin, the Heidelberg spar, which is now at the front of the queue in the construction yard.

In Mozambique, we have continued to make good progress on all fronts. Of particular note, we achieved our reserve certification for Area 1, supporting initial liquefaction trains associated with Anadarko-operated Prosperidade Complex, and this development remains on track towards achieving first cargoes in 2018.

Exploration continues its industry-leading results. In Mozambique, we had an additional exploration success with the Orca #1 well in Area 1, which encountered approximately 190 feet of natural gas pay in a separate accumulation fully contained within our block. We have 2 appraisal wells now planned to delineate this discovery. And the Orca enhances our development options and flexibility in Mozambique.

In the Gulf of Mexico, we've been very busy, and we've delivered incredible success so far this year. Accelerating the value of the newly discovered Shenandoah Basin is critical. This is one of the company's largest discoveries ever in the Gulf of Mexico. A short distance away in the same basin, we participated in the Coronado discovery, which encountered more than 400 net feet of oil pay, and sidetracked operations are already under way. Additionally, drilling is ongoing at the nearby Yucatan prospect, which is our third exploration well in this new basin. We recently announced the Phobos discovery, which encountered approximately 250 feet of net oil pay in the Lower Tertiary. Further appraisal activity is now being evaluated, and we will incorporate data from the well into our geologic models. Phobos is located about 11 miles south of our Lucius development, which could enhance its economics as future infrastructure is installed. As busy as the first quarter was, we had even more wells drilling and planned during the balance of the year in the Gulf of Mexico.

Operationally, we had another very strong quarter, as detailed in our operations report on our website. If you've had time to review this, you saw us reduce unit costs, improve wellhead margins and deliver operating efficiency across our active plays. Our deep and balanced portfolio enables Anadarko to grow production and reserves with value. Capital allocation in our development portfolio continues to be driven by rate of return, which favors oil and liquid-rich gas opportunities. And despite the current strengthening in the natural gas prices, Anadarko will need to see sustained prices well above the current spot for dry gas opportunities to compete for capital in our portfolio.

Recapping our financial results for the quarter, we generated discretionary cash flow of more than $2 billion, reported net income of $0.91 per fully diluted share, or $1.08 per share, excluding certain items affecting comparability. Our strong cash flow generation and value-accelerating monetizations enabled us to strengthen the balance sheet and improve our leverage ratio to 32%.

The first quarter's results are a great foundation for another outstanding year for our company. And as I said earlier this year, we believe 2013 could be a breakout year for Anadarko. We have a number of exciting things ahead of us throughout the balance of the year: to deliver better than 5% year-over-year sales growth; to receive the court's ruling in the Tronox case, where we remain confident in the merits of our case; continue to be active worldwide in exploration and deliver a portfolio of success similar to prior years; and to continue to realize value via active portfolio management, where select monetizations are going to allow us to reinvest this avoided or realized capital in other parts of our business to achieve growth through value.
With that, we're happy to take questions. And operator, we'll turn it back to you.

Question and Answer

Operator

[Operator Instructions] So your first question comes from the line of Brian Singer with Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Can you expand a little on the comment with regards to Jubilee production, that you expect the gas handling capacity to increase oil volumes into late 2013? Can you just kind of give us an update there on well performance at Jubilee? And then, when you think about where oil volumes can go, is it -- does it get to the 120,000 barrel-a-day capacity and stay there? Or should we expect something above or below?

R. A. Walker
Chairman & CEO

Sure, you bet. Doug Lawler and I will sort of tag-team you on this one. I think some of what we're talking about there, you'll hear more from the operator, Tullow, but we are very encouraged for the things that we have talked about today that we can point to with respect to how well that field is progressing. And, Doug, you might take just a few minutes and talk specifically about some of the things we're seeing.

Robert Douglas Lawler
Former Senior Vice President of International & Deepwater Operations

Sure. Brian, as you know, the facility is rated at 120,000 barrels a day. We're currently producing about 110,000 on average. The work that you're describing is to do some topside facility work that will result in giving us some additional gas injection capability. We see that being able to get us up to around 120,000 barrels a day from the 110,000 at present. The current drilling activity, the Phase 1 program, as well as the asset jobs that we've conducted had performed really well. At present, the flow potential from the field is greater than what we can produce through the FPSO right now, and so we have some additional asset stimulation work as well as a few other Phase 1A wells that'll be drilled later this year and into 2014. But we're hopeful that this additional injection capability will get us up to the 120,000. In our forecast for the year, we expect it to be in the 110,000 to 120,000 range as that gets implemented. And the target time for that is targeting in the third quarter.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Great. And then as a follow-up, your natural gas production has been perhaps surprisingly resilient certainly relative to your guidance and then especially in the price environment. Obviously, this kind of question varies by area. But can you kind of talk to whether -- to what extent this is being driven by backlog reduction in areas such as the Marcellus and where that stands versus greater gas in the production mix in some of your associated gas areas, or just better well performance overall?

R. A. Walker
Chairman & CEO

You bet. Since most of this is an onshore issue for us, I'm going to ask Chuck Meloy, if he would, to address the question.

Charles A. Meloy
Former Executive Vice President

Well, Brian, as you've seen, our gas production has been steady to slightly up. Now the -- there's 2 or 3 good reasons for that. The first off is just the Marcellus performance. If you look year-over-year, the growth has been phenomenal. Our sales are up about 71% from prior year, and that's the combination of completing the wells we're drilling and unloading the backlog that was in our non-op position and getting the infrastructure completed in that area. And as all that has come together, you've seen some

very cost-efficient, low-OpEx-cost, really good margin for gas come online as some of the lowest-cost gas in America. So it's been an exceptional performing asset for us. We've also seen just a really strong performance from the IHUB area, where when we originally came in, we would have -- we had exceeded the Tcf production from that field and the wells have outperformed our expectations and continued to deliver gas that, quite frankly, we didn't see in our curve [ph]. So those 2 and smaller other bits and pieces have added up to a really good story for us.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

And is your Marcellus backlog now at a normal level? Or is it still an abnormal backlog? Where do you see that going?

Charles A. Meloy
Former Executive Vice President

Well, I'm not sure what normal would be, Brian, but the -- I think we're in a position where we've got it worked down. And Chesapeake in particular has worked theirs down quite considerably. And the addition of infrastructure out there, I think, has had as big of an impact on as just completions. So we're starting to open up the pipes and give us some room to flow, and that's been a big help in our production numbers.

Operator

Your next question comes from the line of Scott Hanold with RBC Capital Markets.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

When you look at your success in the Gulf of Mexico, can you talk about how you're looking at shipping around activity? I mean, you're looking to appraise the Shenandoah or Phobos in the near term or by the end of the year. And what potential impact does Raptor have on -- your thoughts of kind of what comes next?

R. A. Walker
Chairman & CEO

Well, let me take that in part and have Bob Daniels take it in part. I think what you've seen is we continue to have extraordinarily good success, both with exploration and development drilling in the Gulf of Mexico. It's -- you've got Lucius and Heidelberg coming on to the next mega projects from the Gulf of Mexico, with oil production starting next year for Lucius. And as we look at our inventory, I think you can continue to expect that we'll manage that pretty actively just like we have been. And frankly, additional exploration success there is not critical. We're always happy when we have it, obviously, because it gives us more optionality. But I'm going to let Bob address the question of exactly what he sees from an exploration standpoint through this year and next, because we do have a lot of things still to drill. You made reference to one well that is drilling, but we have a lot of other things still planned to drill through the course of this year.

Robert P. Daniels
Former Executive Vice President

Yes, Scott. Bob here. We've had really, really good success there, and that's a great problem to have with how we're going to appraise these things. Shenandoah obviously needs additional drilling. We plan to get a rig out there before the end of the year to drill the next well on it. We still are awaiting on the Yucatan results just south of us, about 3 to 4 miles south of us. That's going to be really key for the overall Shenandoah-Yucatan area. And then we are drilling an appraisal well over at Coronado, where we're the non-operator. Regarding Raptor, we're not down on that well yet, so we'll have to see what we find. But we're very hopeful we'll need appraisal work there. Again, a good problem to have, and we'll just have to roll it into our overall rig planning based on the results that we see. But we do have Shenandoah scheduled for right at the end of the year to get a rig back on and do another appraisal well there.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

And is there any change to your guys's plans in terms of what you've done in the past with a fair amount of success to potentially monetize some of these successes prior to development? Does that continue to be something you look at in the Gulf?

Robert P. Daniels
Former Executive Vice President

Absolutely. You've seen what we did at Lucius and what we did at Heidelberg and the value that we were able to realize for those opportunities. So that's a great model. It carries our forward capital and puts a marker as to what the value of these discoveries are.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. And one final question, if I could. Permian volumes are down a bit in the quarter sequentially. It looks like you guys are still fairly active there yet. Was there a specific reason for that?

Charles A. Meloy
Former Executive Vice President

Well, the Permian has been a great performer for us. I -- the reason for the down is essentially the transformation in the operatorship on our non-operated position. And those guys are just getting up to highway speed and doing a good job, and they're starting to build up their program and I look for that to reverse pretty quickly.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. Is that sort of the Chesapeake sales to Chevron and Royal Dutch?

Charles A. Meloy
Former Executive Vice President

Yes.

Operator

Your next question comes from the line of Charles Meade with Johnson Rice.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

On Mozambique, I saw that you had in your operations report that you received the reserve certification from a third party for the Prosperidade complex. But I was curious if you could maybe offer some detail on where that same process is for the Golfinho/Atum complex.

Robert Douglas Lawler
Former Senior Vice President of International & Deepwater Operations

Sure, Charles. This is Doug Lawler. The -- where we see it at present, we have some additional testing work in working with a third-party consultant there. It's on -- in progress, and we still are very confident in achieving that. The time line we've provided for that is also in 2013. And so along with the success there in this phenomenal exploration discovery, we continue to see progress on the reserve certification necessary to -- for us to move forward.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Okay. And then returning to the Shenandoah mini-basin, this might border on fantastic, but the -- I think when we got the press release from the operator on the Coronado well, I think they just logged it, but they hadn't taken pressures or anything. And I think -- I believe I read that they're side-tracking down-dip there. But I know that's, what is it, 3 blocks, 2 blocks to the east and 1 block to the south. And so it's a long way away from Shenandoah. But have you guys -- presumably, you have a pressure test in that reservoir now. And can you offer any kind of view on whether you're in the same pressure regime as the Shenandoah discovery and whether there's any outside chance that this all could be -- have a common oil-water contact?

Robert P. Daniels
Former Executive Vice President

Yes, Charles, the Coronado and Shenandoah accumulations don't look like they're going to be connected. The data doesn't really support that. It's a long ways away, and we go through a massive syncline to get our -- to the Coronado prospect. So we are in the process of appraising that down-dip and see what kind of oil leg we have below us. And so we're looking forward to that. I will say that on the Shenandoah/ Yucatan complex, which there's about 3- to 4-miles separation, that one very well could be 1 common accumulation, but, of course, we have to get the Yucatan well results and see what it tells us. But structurally and stratigraphically, that one makes a lot more sense than over to Coronado, which is much further away.

Operator

Your next question comes from the line of Doug Leggate from Bank of America.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Al, I wonder if you could share any updates on the monetization process in Mozambique and specifically address how you think the -- any potential tax issues might be tackled as part of the process.

R. A. Walker
Chairman & CEO

Sure, I'm happy to do that, Doug. Actually, if I can, we'll have Bob Gwin do that, and I'll probably have a comment to wrap up with on that.

Robert G. Gwin
President

This is Bob. We're really pleased with the indications of interest that we received a few weeks ago. Obviously, we're in discussions and working on the transaction. I think it's fair to say we expect it would be a 2013 transaction after -- a government approval would need to be received after we reach agreement with a potential buyer. As far as taxes go, we will see. Obviously, the tax situation around Cove was fairly obvious. If we were to sell an asset versus a corporate structure here, that tax would be a little bit higher. And so we're looking at our economics and the bids that we received on an after-tax basis rather than a pretax basis. But we'll be working with the government to determine what the ultimate tax owed will be.

R. A. Walker
Chairman & CEO

Yes. And, Doug, I'd just add we feel like, as we got into this, it would take us a while to come to a conclusion with one of the potential buyers here. And progress so far has been really good, and the indications of interest, as Bob made reference to, were all quite strong, and we're looking forward to bring it to a point where we can talk about it.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Al, forgive me, but are you -- have you got an exclusive here on this?

R. A. Walker
Chairman & CEO

No.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Okay. My follow-up, I don't know who wants to take this, but back to Shenandoah, if I may. I think prior presentations you've shown Shenandoah on a time line out around 2017. I'm just wondering, is it too early to really think about development options here? And if not, could you give us some framework as to what we should be thinking about in terms of when you may bring it up on to production? I'll leave it there.

Robert Douglas Lawler
Former Senior Vice President of International & Deepwater Operations

This is Doug Lawler. Your comment is exactly right. It's very early, and we're looking forward to the appraisal program. Obviously, it's a very big discovery, and we'll be bringing more information forward as we learn more and study those options to bring it to development.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Are you thinking about unitized development, Doug? Or would this be as it's still too early to talk about that?

Robert Douglas Lawler
Former Senior Vice President of International & Deepwater Operations

Still very early, Doug. And I appreciate the question but, at this point, it's just -- it's very early.

Operator

Your next question comes from the line of Dave Kistler from Simmons & Co.

David William Kistler
Simmons & Company International, Research Division

Real quickly, looking at 2Q production guidance, 1Q had a nice jump up from 4Q. Can you guys kind of define what's delineating sort of the drop-off in production?

R. A. Walker
Chairman & CEO

Yes, I think there's a couple of reasons. I think Chuck will walk you through some of that. I think, Dave, the word of caution I would have is, as best you guys can, try to look at this as a year-to-year rather than a quarter-to-quarter. I know there is some need to do the quarter-to-quarter, but I think as we've continued to address these questions, it seems like almost every quarter we'd certainly guide to something we think we can hit. We see issues out there that we think we're trying to manage around. And I think, as you can fully appreciate, as we think about our business, we don't think about it quite as much quarter-to-quarter as maybe others do.

Charles A. Meloy
Former Executive Vice President

Yes, Dave, this is Chuck. There are some -- if you go through the announcement that we made, the big issue that we face in second quarter is the fact we had an accelerated lifting in the first quarter, and that's pretty straight math. The other one that we have dealing with -- that we're dealing with currently is we're in the middle of doing the tie-ins down in the Brasada area. And so we'll have quite a bit of downtime associated in our Eagleford production area as we tie in the Brasada plant and the associated facilities in the field together. And that's just going to be an up-and-down deal, and we're going to do it safely and

carefully, and we're taking a very conservative approach to how we put all that together. And it's just -- it's part of the growing pains we talked about a couple of quarters ago. As we start this infrastructure build-out, you get into these spots from time to time that you incur a lot of down time. And this quarter is going to be one of those as we significantly enhance our infrastructure position and not just the Eagleford but in the Wattenberg and the Permian as well but, to a lesser extent, from production impact.

David William Kistler
Simmons & Company International, Research Division

Okay, I appreciate that. Then maybe kind of getting back to annual levels, if I look at 1Q CapEx, obviously it comes in at a run rate well below what your targeted full year CapEx is. Can you kind of walk us through the progression of that throughout the year? Or should we be kind of traversing that to the lower end of CapEx?

R. A. Walker
Chairman & CEO

No, Dave, I think you should expect that we're going to be to the midpoint or the upper end of that range. I wouldn't extrapolate from the first quarter that we're going to underspend for the year. It's just the timing of when we expect those capital plans to actually work their way through into reality. And we still anticipate a fairly strong year of capital spending but not outside of the guidance that we've given you and everybody else. First quarter is just sort of like some other things, just a timing issue and not a lot more than that.

David William Kistler
Simmons & Company International, Research Division

Perfect. One last one, if I might, just on the Wattenberg. Can you guys give us an update on kind of latest leading-edge, lateral lengths, costs, production associated with those longer lateral spacing? I mean, obviously, that was a home run this quarter, so I'd love to hear any kind of incremental update you have there.

Charles A. Meloy
Former Executive Vice President

Yes, Dave, I'd probably view it as a grand slam. It's been a wonderful quarter for us. Year-over-year, our production has gone up substantially from -- in the mid-20s, 26,000 barrels a day to 44,000 barrels a day on the oil side, which is a huge uplift. And that's because we're in the middle of doing a lot of optimization work not just with lateral lengths but with spacing, completion design, facility design, putting the big-diameter pipes in the ground that allow us to move these incredible quantities of hydrocarbons that are coming out of these wells and all the infrastructure associated with the Lancaster plant. So we're in the middle of all this. It's a big optimization effort. What we've seen is very similar to what Noble has announced with regard to their pilot test. Longer is better to a degree, and we've seen more and more recovery. There's a pretty straight correlation between lateral length and EUR. And I think that you'll continue to see that there's a natural limit in a risk element that we have to take into account with regard to so much completion drilling in these wells but -- if you get too long. But what we're trying to do is optimize all of those parameters, not just length but the distance between wells, the distance in the number of wells we've put in each section or each unit. And we're in the middle of all that. We feel like it's a little early to come to any conclusions on specifics of that optimization, but we're on the job and we're accelerating the value out of that thing. We're up to 12 rigs now. We started out thinking we'd drill around 300 wells this year. We'll end up drilling around 340. Most of them will be longer laterals than what we originally intended. And so we know the value of this thing. It's immense, and we're on the job to accelerate that value.

Operator

Your next question comes from the line of Arun Jayaram from Crédit Suisse.

Arun Jayaram

Crédit Suisse AG, Research Division

I just wanted to maybe follow up on the Wattenberg. Really strong growth. I think you achieved 113,000 BOEs a day. Al, I was wondering if you can comment. Your guidance for the year was 121,000. Do you see any upside to that number just based on the pace of what we've seen thus far this year?

R. A. Walker
Chairman & CEO

Well, I'll answer this in part and Chuck will answer it in part. We don't guide to the midpoint of our expectations. We kind of guide to what we think we can achieve. So sure, if we're able to achieve better-than-average results, we should actually achieve better than what we projected. But we also keep in mind that there are things that we have no control over, weather being one of those, mechanical issues being another. So if you can appreciate, we don't try to pull the string too tight when we're looking at guidance, and we like to be able to continue to have the types of results year-over-year that give us good momentum, good confidence around being able to achieve what we say we're going to achieve. So I always expect if things go well, Arun, that we can actually always be in a position of overachieving, but I am always mindful as well that there are things we can't control.

Charles A. Meloy
Former Executive Vice President

And...

Arun Jayaram
Crédit Suisse AG, Research Division

I guess just a quick follow-up to that is I'm just saying as you're ahead of plan, at least for -- regarding that guidance, are there any other infrastructure things that we need to think about in the balance of the year that may constrain that growth until you get Lancaster online?

Charles A. Meloy
Former Executive Vice President

Arun, this is Chuck. We do have -- the Lancaster tie-ins will come in during the fourth quarter. And so we've placed in our guidance a reasonable downtime expectation in the fourth quarter. We're hopeful that during the course of the year, that we can make those tie-ins sort of opportunistically, such that we don't incur all that downtime. That would enhance our volumes for the year. And I think the other thing that's really cool out there is we've now managed to get -- our total water fee is on -- we got water on demand. And so our completion machine is just working fantastically. The guys are doing just a fantastic job of lowering the cost. We saw over $350,000 per well savings in the last quarter with regard to lower water cost, lower water delivery cost and improved completion cost. And so all that's working in our favor, and the drilling folks are doing a fantastic job in improving our drilling efficiency and spud-to-spud time. So the machines are -- is working faster, and that gives us an opportunity to enhance our results. And all that's got to be over-printed [ph] with what else is going on in the field to enable that to be evacuated into the markets. And -- but between the Lancaster plant, the expansion on White Cliffs, the tie-ins at Texas Express, we've got a lot of things -- Front Range Express, sorry -- we have a lot of things going on in the field that's going to interrupt our production at some point, and that's what we're trying to take into account.

Arun Jayaram
Crédit Suisse AG, Research Division

That's helpful. And just one quick question or clarification on the full year guidance. Al, you did bump the upper end of the guidance by a couple of million barrels, yet you left the bottom end flat. Can you just put that into context? Is that just conservatism? Or any other thing that you're thinking about regarding the bottom end?

R. A. Walker
Chairman & CEO

Yes, I think it just goes back to we've taken, through the course of the year, a fairly conservative view on ethane rejection, and that's the reason that we've guided the way we have at this point.

Operator

Your next question comes from the line of Joe Magner with Macquarie.

Joseph Patrick Magner
Macquarie Research

I'm just curious if you could provide an update on the monetizations that are potentially forthcoming. A couple have been talked about as possibilities, but anything that we should be on the lookout for?

R. A. Walker
Chairman & CEO

Well, I'm going to -- if I can, I'll let -- get -- let Bob Gwin give you a little more color. But I think of all the things we're working on, the one that's got the most immediacy associated with it, we talked about earlier, in Mozambique. But as you can imagine, I made the comment earlier, we're very active managers of our portfolios. That's hardly the only thing we're looking at, at a point in time. So with that, let me turn it over to Bob.

Robert G. Gwin
President

Yes, sure. The only thing I'd add really beyond Mozambique of note is something I mentioned on the investor call back in February, and that is Brazil. Obviously, we continue to work that. It's a bit of a challenge because there's a unitization process or unitization study under way that BP, as the operator of the BM-C-32 block, is negotiating. But nonetheless, we decided it was appropriate to move forward with a potential monetization there. That process is in the really early stages. The timing of completion is going to be unknown because it is a little bit complex due to the unitization and then subsequent need for ANP approval. And so we'd be hopeful to get that done later in 2013, but it's hard for us to drive the time line. It's really just a matter of us proceeding kind of diligently to get that done, and we'll continue to keep the market apprised as it gains a little more shape. Otherwise, there's lots of things that don't rise to the level of mentioning at this point. But as you've seen, things we've done like our OCI deal we did in the first quarter, various sundry, smaller things, our EOR deal that we did with LINN last year. There's a variety of these types of things that we continue to work on. And we'll continue to try to fine-tune the portfolio of things that don't work quite as well for us, attractive assets but might fit better in somebody else's portfolio, and then we'll continue to focus our capital and attention on the things that are our highest points of opportunity.

Joseph Patrick Magner
Macquarie Research

Okay. And then with respect to the Mozambique situation, you touched on reserve certification process. Can you, I guess, update us on where the discussions lie, perhaps not on the detailed level, obviously, but just regarding the pricing dynamics of offtake agreements and what we might expect to see and how we might expect that to play out?

R. A. Walker
Chairman & CEO

Sure. We've got Scott Moore here with us, who runs Marketing globally for Anadarko. And if I could, Scott, why don't you address that?

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

I think we're excited by the interest in the market that we've seen in our Mozambique product. It's a premium product that should deliver a premium price. We do look primarily at oil indexation than the

pricing, which is well established with the high-quality Asian buyers that we target for a greenfield project like this. And we look forward to working on those structures and hope to talk to you more about it later this year.

R. A. Walker
Chairman & CEO

Joe, as you might imagine, given the advantages of geography and a lot of other things, the buyer community for LNG coming out of Mozambique is pretty deep.

Joseph Patrick Magner
Macquarie Research

Okay, there have been some, I guess, some mentions in the media that perhaps there's some linkage to natural gas prices or Henry Hub prices. How is that going to influence the calculation or the pricing schemes?

R. A. Walker
Chairman & CEO

Yes, I think there are certain utility buyers in Eastern Asia that are looking to try to move away from a completely oil-indexed contract. We're looking at it in terms of what the effective price per Mcf or Mbtu is for us and how that gives us project economics. We certainly are not today -- have not entered into any contracts that would incorporate that, but we've certainly listened to the buyers that they've talked about it. And, Scott, please add anything you'd like.

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

I think the key for us is we look for things that deliver comparable value, and there are a number of ways that can be accomplished. And we do try and reflect our buyers' concerns, but the value has to work for us as well.

Operator

Your next question comes from the line of Ross Payne with Wells Fargo.

Ross Payne
Wells Fargo Securities, LLC, Research Division

I was just wondering if you could give us any more color on the timing of the Tronox potential settlement, when you think that may occur and if there's any kind of change in what kind of financial impact that may have.

R. A. Walker
Chairman & CEO

Ross, I wish I had a crystal ball and could give you an accurate prediction. The reality is I don't have one of those or haven't found it in my closet yet. We really don't know when this judge is going to come back. In our most recent Q filing of this week, we reiterated our range of $0 to $1.4 billion. That's our best estimate. We still think the case that we have is very strong, and we think, more likely than not, that we will win. And so, therefore, that's the construction of the range. But the timing of when this judge will make the ruling is very difficult for us to give you any direction on, but I'm going to let Bobby Reeves try.

Robert K. Reeves
Former Executive VP & Chief Administrative Officer

I think that's right, Al, that look back at our 10-Q, we've not change. We believe it's more likely than not that we will prevail. There is a potential loss range of $0 to $1.4 billion based on our best estimates. We still believe that the evidence of the trial was that Kerr-McGee properly capitalized Tronox when it was IPO-ed and that Kerr-McGee wasn't responsible in any way for the financial struggles or bankruptcy of

Tronox. And we believe that, that was pointed out clearly in the trial, and we believe that the ruling from the judge should prevail for us and give us the clarity that's right now an uncertainty on our company. So we're looking forward to the ruling.

Operator

Your next question comes from the line of David Tameron with Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

The big cash flow generation in the quarter in the balance sheet, obviously it's some placeholder for Tronox or whatever. But can you talk about what your plans are for that free cash flow as that continues? Obviously, you have some big projects, but thinking dividend and any other thing you want to throw out there?

Robert G. Gwin
President

It's Bob Gwin. Obviously, we're working to preserve the current strength of the balance sheet while we have this uncertainty related to Tronox that was just discussed. As we move forward, we're going to continue to reduce leverage to a degree. We obviously are focused on a strong credit quality and on an appropriate credit quality for the structure of our global business, our exploration business. But as we mentioned a little bit previously, we're going to revisit dividend policy as we go forward if it doesn't take a lot of work to look at our future cash-flow-generating capability and the way that we've focused on monetizing assets and leveraging the use of other people's money in our development dollars. And that leads to some relatively strong cash generation over time, which is the goal of our business model. And when we do that, we'll visit -- revisit the credit quality, do some liability management and make sure the capital structure is optimized for our business model. So it's a work in progress, but I think we'd stay essentially where we are until we get to the other side of the current uncertainty.

R. A. Walker
Chairman & CEO

And, David, this is Al. I think given the way we've been able to use our cash flow pretty effectively and staying within that with CapEx, as we've continued this, Bob made referenced to the fact of using third-party capital in a lot of our bigger mega project development, our ability in the future to continue to be even more cash efficient and capital efficient should lead us to a good place when we're able to make an announcement on the dividend payout policy.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

All right, that's helpful. And then as I think about your big portfolio in the U.S., I imagine there's a lot of plays that you haven't talked about you guys are chasing. And the one that popped up in the last month or so has been this Northeast Colorado play. Can you talk a little bit about what you have out there? And then anything else you want to give us as far as what you're working on in the U.S.?

Charles A. Meloy
Former Executive Vice President

David, this is Chuck. As we work our -- the U.S. onshore exploration program, you may have noticed, we're investing about $300 million a year in new oil plays. And there's roughly half a dozen of those located around the U.S., and we're exploring and appraising in each one of those. And we haven't released any results. We typically don't until we actually do have a pretty good idea of what we could expect from the plays. And I will say we have some very encouraging early results in several of those, and we look forward to them playing a bigger and more prominent role in our portfolio going forward. And each offers the opportunity to substantially enhance our EBITDA per barrel and value proposition for you guys.

R. A. Walker

Chairman & CEO

I'm thinking Colorado as well. You probably have seen it, David. We have a very large mineral interest position right in the middle of what looks like to be a new play. And I might ask, if I could, just to see if Chuck will want to comment just a little bit about our acreage position there.

Charles A. Meloy
Former Executive Vice President

Well, there's been some press about the plays going on in Southeast Colorado on the Arch and the Mississippi -- Mississippian play. And it is right in the middle of our land grant, where we have mineral interest in every other section. And our total acreage position there is approaching 800,000 barrels -- I mean, 800,000 acres net. So it's a very substantial position, and we're well positioned to take advantage of any success that industry would have on the Arch.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

All right. And at this point in time, are you waiting for others to prove it up? Or what's -- are you guys active out there in the -- around the Arch?

Charles A. Meloy
Former Executive Vice President

Well, the advantage of having perpetual mineral positions is you can let others prove up the play, and we've been actively monitoring and engaging in some small farm-outs to encourage activity. And what we've seen so far is very promising. We have permitted wells in the area, but we haven't yet drilled one. And there's a lot of inbound interest on that play, and so I'm -- I feel fairly confident that we'll see some good value realization in the future.

Operator

Your next question comes from the line of Eliot Javanmardi of Capital One Southcoast.

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

I believe this question is probably for Chuck. Just I noticed there was significant decline in the CapEx spend onshore while you maintained your growth, and I think it was to the tune of maybe $300 million or so. Just curious, how much of that would you kind of say was associated with coming off of infrastructure spend on any projects you finished as opposed to just the efficiency improvements that you have across-the-board?

Charles A. Meloy
Former Executive Vice President

Yes, Eliot, great question. There's -- it's some of both. We've actually had some really nice savings in our drilling program. I mentioned earlier like in Wattenberg where we've -- we're saving money on the drilling because we're doing it a little quicker, and we're also saving $350,000 on each completion by changing up our completion design and using slick water-type activities. The -- we also have completed a fair share of our Midstream spend in the first quarter. And although we still have some big projects yet to come online, like Brasada and Lancaster and others in combination with our WES position, our Midstream spend going forward is as -- is tailing off to some degree off the high spend of these big plants. And once we get that in the rearview mirror, we're back to sort of a normal run rate. And the combination of that and the timing of -- or the continuation of the JVs that we have down in the Maverick has just subdued our capital in the first quarter, but we're running 47 rigs in the U.S., we're building 900 million of cryo and we're drilling a bunch of wells and successfully drilling a bunch of wells, most of them horizontal, the vast majority of them horizontal with large completions. And that'll keep our capital spend right up through the rest of the year.

R. A. Walker
Chairman & CEO

And, Eliot, I know you're absolutely aware of this but just to make a further comment about it. As you've seen this in the past with our Midstream infrastructure, we ultimately will find ourselves selling that to Western Gas and reinvesting that capital either in upstream or in other infrastructure. So even though we've made some big capital commitments in the Midstream, we do sort of have our own -- a way of looking at that and using Western Gas in that capacity, and I think that's worked out very well for us.

Charles A. Meloy
Former Executive Vice President

And to that end, we sold an asset gathering in the Marcellus to Western Gas earlier this year for almost $500 million, which brought cash back into Anadarko to reinvest in the E&P operations. So it's continuing and working well.

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

Great, I appreciate that. I did see that in the ops report, too, and it was spelled out pretty clearly. Just a quick follow-up. You touched upon this a little bit already with some of the onshore plays. And I'm just curious, do you have any comments on maybe the prospective Powder River and what you got there? And that's it for me.

Charles A. Meloy
Former Executive Vice President

Yes, Eliot, in the Powder River, we have a very large land position, as you know, over 350,000 net mineral acres up there. And we've been active. We've drilled probably in the order of 20 wells into the deeper section, looking for oil plays. That basin is proving to be very oil prone, particularly the southern end of the basin. And it's an exciting place to play because there's multiple horizons that have paid off. We've been involved in Frontier, Sussex, Shannon and Niobrara exploration to date, and each one of those has some promise. So we're actively moving those forward. We're in appraisal mode in those areas. So it's an exciting area for us, and we're hoping we can put some size and mass around them so we can put our machine to work.

Operator

Your next question comes from the line of Alex Heinbruther [ph] from Millennium.

Unknown Analyst

Two questions. First, can you comment on the cost structure in the Eagleford like you did in the Wattenberg? And any kind of trends in all-in costs to bring the wells online? And there's been questions to the size of the Phobos structure. I think John told some of the analysts that it was about 8,000-acre structure. And then -- but Mr. Flores [ph] on his call the other day said it was a 10,000- to 15,000-acre structure. So I just hope you can clear that.

Charles A. Meloy
Former Executive Vice President

I'll -- I'll take the first one. This is Chuck.

The Eagleford is doing quite well. We've continued to drop our drilling times down, and we drilled a whole number of less-than-10-day wells now. And so if you put everything in play and look at the completion cost, we're now drilling, completing and equipping those wells in the order of $5.5 million to $6 million. And the EURs are north of 450. So we've had some really strong economics. On the OpEx side, I think that's a -- it's a great, great story, where our cost structures continue to fall and we're operating the Eagleford for -- in the order of $2 a barrel now. And that's been a great story for us. So you get tremendous margins with the oil production that we have and the gas plant liquids that we recover with

very rich gas. So the story is good out there, cost structure is good. We're making a really nice return on those wells and I anticipate that will continue and maybe even improve once we get Brasada online, where we can really stabilize production and not have so many ups and downs as we're putting the infrastructure in place. And once we get that field stabilized, I think you'll see some really, really nice gains in our production profile.

R. A. Walker
Chairman & CEO

Yes. And, Alex, regarding Phobos, the structure is very, very large. It's a big 4-way closure. What we're talking about is what we think we have in the accumulation to our lowest known oil. We think we've got about 8,000 to 9,000 acres in that closure that potentially could be full of hydrocarbons. So I don't know whether that's a difference between what they're saying and us. The other is, of course, different interpretations. You've got different philosophy transforms that could give you different structural interpretations. It's a very, very broad, lower-leaf structure, so it wouldn't take much to change that. But what we see is about 8,000 to 9,000 acres of 4-way closure to our lowest known oil.

Operator

[Operator Instructions] And your next question comes from the line of Amir Arif from Stifel.

Okay. And there appears to be...

R. A. Walker
Chairman & CEO

I'm sorry, go ahead, operator.

Operator

Yes. And there appears to be no further questions.

R. A. Walker
Chairman & CEO

All right. Well, I do want to one more time say thank you to everybody that was with us today. Your management here could not be happier with the first quarter. And I'll say one more time we think 2013 is a breakout year for this company, and the balance of the year looks really exciting. John?

John M. Colglazier
Investor Relations Professional

Thank you much, and we'll talk to you all later. Thank you.

R. A. Walker
Chairman & CEO

Thank you.

Operator
Ladies and gentlemen, this concludes today's conference call. You may now disconnect.

Exhibit 84

Corrected Transcript

29-Jan-2015

ConocoPhillips (COP)

Q4 2014 Earnings Call

CORPORATE PARTICIPANTS

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VP-Investor Relations & Communications

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Chairman & Chief Executive Officer

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

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JPMorgan Securities LLC

MANAGEMENT DISCUSSION SECTION

Operator: Welcome to the Fourth Quarter 2014 ConocoPhillips Earnings Conference Call. My name is Christine and I will be your operator for today's call. At this time all participants are in a listen-only mode. Later we will conduct a question and answer session. Please note that this conference is being recorded.

I will now turn the call over to Ellen DeSanctis, Vice President Investor Relations and Communications. You may begin.

Ellen R. DeSanctis

VP-Investor Relations & Communications

Thanks, Christine, and greetings to everybody. Joining me in the room today are Ryan Lance, our Chairman and CEO; Jeff Sheets, our EVP of finance and Chief Financial Officer, and Matt Fox, our EVP of E&P. Really three quick very administrative points before we launch into our remarks here. We will make some forward-looking statements this morning. The risks and uncertainties in our future performance are covered on page two of today's deck and in our periodic filings with the SEC. This information can also be found on our website.

Next if you haven't done so, save the date for our 2015 Analyst Meeting on April 8 in New York City. We will be providing some additional logistical details on that event soon. And then finally, during Q&A this morning we're going to limit questions to one with a follow-up so we can accommodate the call queue. We appreciate your support there.

So now let me turn the call over to Ryan.

Ryan M. Lance

Chairman & Chief Executive Officer

Thank you, Ellen, and thanks to all our call participants this morning. So I'll start by making a few quick comments about 2014, then I'll jump into our view of 2015 and the actions we're taking to manage through this current period of very low prices.

Of course were also spending a lot of time thinking about the future beyond 2015. It's a bit early to talk about that today but as Ellen mentioned, we'll speak to that in our April Analyst Meeting where we'll be ready to address our longer-term view of the sector and how we're positioned to succeed.

So if you turn to slide four, this is our company-level said/did chart that we show during every quarterly call. Certainly 2014 seems like old news but I think it's important to spend a minute recapping our results for the year.

Operationally we hit our volume targets and achieved 4% year-on-year growth and I think that's a pretty big accomplishment for a company our size. The growth came from the startup of five major projects, ongoing ramp up in the Eagle Ford and the Bakken and a successful turnaround season across our operations. We also discovered two new oil plays in offshore Senegal.

Financially we generated $6.6 billion of adjusted earnings, or $5.30 per share for the year. This includes fourth quarter adjusted earnings of $742 million or $0.60 a share, obviously reflecting weak fourth quarter prices. We

ended the year with $5.1 billion of cash on the balance sheet and also exceeded our price normalized cash margin growth target with more than an 8% improvement.

On the strategic front we achieved a strong organic reserve replacement ratio of 124%. And by the way, the three-year average organic reserve replacement ratio is 153%.

We completed the final piece of our announced asset disposition program with the closing of the Nigeria sale and we increased our dividend by 5.8%.

That's a quick summary. The key takeaway here is that we did what we said we'd do, not just in 2014, but also over the past three years since the launch as an independent E&P company. We executed our stated plan almost to the letter and in the last quarter, oil and gas prices began their accelerated decline. So let me discuss what that price decline means for our company in 2015, if you'll turn to slide five.

There's a lot of debate right now about the duration of the current low oil prices. But we're assuming that they'll stay low for 2015, and we're taking decisive actions accordingly.

Our actions are driven by our priorities which are unchanged since the time of the spin. The dividend remains our top priority for capital allocation. The next highest priority remains getting to cash flow neutrality in 2017. With these priorities in mind, we're going to use our capital and our balance sheet flexibility to manage through this downturn.

So first, CapEx. This morning we announced a further reduction in 2015 capital to $11.5 billion. That's $2 billion lower than the $13.5 billion that we announced in early December. This means we cut capital by a third relative to 2014 spending. In making these cuts, we're exercising flexibility we've built over the past few years, coring up the portfolio, adding scalable, unconventional inventory with a low cost of supply and executing the vast majority of our major project spending. And that's why we can adjust our capital program while preserving future investment opportunities. And in 2016 you'll see more capital flexibility as additional major project spending continues to roll off. At our revised capital level, we still expect to deliver 2% to 3% growth in 2015 versus 2014.

Now in addition to conserving capital through scope reductions, we're aggressively identifying and capturing cost savings through our supply chain efforts. At this time, our revised $11.5 billion budget anticipates capturing about $500 million of deflation in 2015. Most of this will come from our Lower 48 unconventional business. Now, my management and myself, we review two dozen categories of costs globally every month and we're actively pursuing additional cost reductions for this year and beyond. As one of the largest purchasers of industry goods and services globally, we expect to benefit significantly in future years before any sustained deflationary cycle.

We're also looking beyond supply chain to reduce costs through self-help efforts. As an example, in Europe we recently announced operating costs and G&A reductions and we'll see additional cost reductions that are being implemented across the rest of the company.

In addition to managing OpEx and CapEx, one of the flexibility levers we're prepared to use in 2015 is our balance sheet. We're coming into this cycle in a strong position and that will serve us well. We have cash on hand and a significant capacity that we can use and Jeff will provide more detail on those plans.

So we're taking the 2015 challenge head-on. We're conserving CapEx, we're aggressively pursuing supply chain and self-help cost reductions, we'll utilize our financial capacity as needed. We've adjusted rapidly to avoid jeopardizing our dividend or our ability to achieve cash flow neutrality by 2017. These decisive actions combined with our flexibility should put us in a good stead to manage through this downturn.

So now let me turn the call over to Jeff and Matt, and then I'll come back for a few closing comments.

Jeff W. Sheets

Chief Financial Officer & Executive Vice President

Thanks, Ryan. As Ryan mentioned, our full-year 2014 adjusted earnings were $6.6 billion. Our full-year earnings slide is in the appendix, but I'll quickly cover fourth quarter earnings.

Fourth quarter 2014 adjusted earnings were $742 million or $0.60 a share. Our operational performance was overshadowed by a roughly 20% drop in realized prices compared to prior periods and a previously announced dry hole in Angola.

A segment breakdown of earnings is shown on the lower right with more detail provided in the supplemental data on our website.

There's one special item to note. In the fourth quarter, an agreement to terminate our long-term obligations at the Freeport LNG Terminal took effect. The ins and outs for the income statement and cash flow are shown in the Appendix, but as a result of the transaction, the company anticipates saving about $50 million annually over the next 18 years. So this was a good long-term economic decision.

On slide eight, I'll cover our 2014 production from continuing operations. We achieved two important milestones in 2014, namely hitting our growth targets for production and margin growth. Our production growth for the year excluding Libya was 4% from 1,472 million to 1,532 million BOE per day. The impact from down time and dispositions was small, and compared to last year, our net gross was over 60,000 BOE per day, primarily from liquids, an area with favorable fiscals.

We also achieved our cash margin growth target and that's shown on slide nine.

For 2014, we achieved an 8% cash margin improvement when normalized on 2013 price s. Despite lower prices, we're not going to lose our focus on cash margins and, in fact, it's as important as ever.

Next I'll review our 2014 cash flow waterfall on slide 10. We started the year with $6.5 billion in cash and short-term investments and generated about $16 billion of cash from operating activities. We cashed at about $1.2 billion of net proceeds from dispositions, mostly from Nigeria. Our 2014 capital expenditures were about $17 billion. After accounting for dividends and debt, we ended the year with $5.1 billion in cash.

Next I'll address the balance sheet flexibility we're prepared to exercise in 2015 as needed, so if you'll turn to slide 11. We've consistently spoken in the last several years about our plans to grow at a moderate rate while paying a strong dividend to our shareholders. The growth in our cash flow was moving us to a position where cash from operations would fund our capital and the dividend in 2017 with the shortfalls in cash flows funded largely by asset sale proceeds. With much lower commodity prices, we, like the rest of industry, need to manage in an environment with reduced cash flow. As Ryan mentioned, even with this dramatic downturn, we remain committed to our strong dividend and reaching cash flow neutrality in 2017, and that's true across a wide range of commodity prices.

As Ryan also noted, the first action we've taken is to exercise flexibility in our capital program, which becomes more flexible over the next couple of years. To achieve our priorities, we will also be using our strong balance sheet

capacity, both cash balances and increased borrowings, to provide funding this year and next. So let me tell you how we're thinking about this.

We ended 2015 with $5.1 billion of cash on our balance sheet, and we need about $1 billion of that cash to operate the company. We don't have any issues with trapped cash that prevent us from accessing our cash balances.

We have ready access to the credit markets, and our debt continues to trade at levels between those of A and AA rated companies. The chart on the right shows indicative borrowing rates for any new issuances in today's markets.

For short-term funding, we have a $6 billion of revolving credit facility capacity that can serve as a backstop for the issuance of very low cost commercial paper. We don't have any debt maturities in 2015. As we assess commodity price environments, both in 2015 and for the next few years, we think it's unlikely that we'll need to increase our debt to a level that would cause our credit ratings to slip out of the single A credit rating range, although it could move lower within the A range if we stay at current commodity price environments for a prolonged period. Our current debt-to-capital ratio is about 30%. We're willing to let that rise, if necessary, as we move the company to a balance of cash flows, capital expenditures and dividends in 2017.

So to summarize, we intend to maintain our strong dividend and continue exercising our increasing capital flexibility to move the company to cash flow neutrality in 2017. Our level of capital spending, rate of growth and the level of debt that we maintain will be the variables that will be influenced by commodity prices.

Now I'll turn the call over to Matt for his operational comments

Matthew J. Fox

Executive Vice President-Exploration & Production

Thanks, Jeff. I want to begin my comments with a brief recap of 2014, beginning with a review of our reserves performance. These are preliminary numbers, but we don't expect any material changes from the final reserves that are published in our 10-K.

We started the year with 8.9 billion BOE of reserves. We produced 598 million and added 742 million organically. These additions came primarily from our Lower 48, APME and Canada assets. This resulted in an organic reserves replacement ratio of 124%. We also sold 159 million BOE, mostly from Nigeria, and ended the year then with 8.9 billion barrels of reserves. That represents a total reserve replacement ratio of 97%. Over the past three years, our total reserve replacement has averaged 129%, and that's after selling assets which generated about $14 billion of proceeds.

So let me put this all in perspective. We launched as an E&P three years ago with 8.4 billion barrels of reserves on the books. Over that time, we've produced more than 1.5 billion barrels and sold over 400 million barrels, and yet we'll exit 2014 with 8.9 billion barrels of high-quality reserves on the books. That's pretty impressive for a company of our size.

Now I want to recap the 2014 operational highlights that contributed to our reserve performance and our 4% production growth. As Ryan and Jeff mentioned, we achieved our production growth target both for the fourth quarter and for the year. Our base assets continue to perform well with strong safety performance and successfully completed several major turnarounds across the portfolio. We achieved another strong year in the unconventionals with 35% annual growth in the Eagle Ford and Bakken. We also conducted multiple pilot tests

and progressed exploration and appraisal activity across our whole unconventional portfolio. And as a result of this work, we're confident that we have an extensive, profitable inventory in these plays for many years to come.

We achieved startups of five major projects across the business: Britannia Long-Term Compression in the UK, Foster Creek Phase F in the oil sands and Gumusut, Kebabangan and SNP in Malaysia. And we made significant progress on our largest major projects at APLNG and Surmont 2 in preparation for startup this year.

We saw progress in our deepwater program, in particular with two discoveries in a new working petroleum system, offshore Senegal and we continue the appraisal on our three major discoveries in the Gulf of Mexico.

Yesterday it was announced that we signed an agreement with Chevron and BP to jointly explore and appraise a 24 block area in Keathley Canyon that includes the Tiber and Gila discoveries. This agreement allows our companies to combine our technical strengths and financial resources to achieve efficiency through scale, reduced sub-surface risk and improve the likelihood of commerciality. So this is a great deal for all three parties.

Next I'll review the capital reductions we just announced and the implications for 2015 activities. We'll start from the $13.5 billion capital guidance we issued in December.

We're not reducing our base maintenance capital because we don't want to jeopardize the strength of our base production or the integrity of our assets.

Our development program spending will be lower by about $1.4 billion. Most of this is coming out of Lower 48 unconventionals where we have a lot of flexibility and where there's a sound economic rationale for slowing the pace of development. In 2015, we'll reduce rigs in the lower Eagle Ford and, sorry, in the Lower 48 by over 60% versus 2014. We plan to run six rigs in the Eagle Ford, three in the Bakken and two each in the Permian conventional and unconventional. At these levels we maintain our land position, meet our longer-term rig commitments and can continue to progress key pilot tests. We retain the flexibility to increase activity in these plays if we choose to.

We're also reducing capital for our major projects by deferring final investment decisions in several conventional assets. And just as a reminder, our initial budget of $13.5 billion already reflected a significant reduction in this category compared to 2014 as projects were completed and as we near startup at APLNG and Surmont. We also exercised $300 million of flexibility in our exploration and appraisal spend primarily in the emerging Lower 48 unconventionals.

As Ryan mentioned, our $11.5 billion capital guidance assumes about $500 million of cost deflation. This is what we have a clear line of sight to capture in 2014 but it's early in the year and you can be assured that we have a significant focus on the effort across the whole value chain. In 2016 and 2017 the flexibility of our capital portfolio continues to improve as more major projects are completed and we believe this flexibility combined with a strong base portfolio positions us well for a potentially volatile few years ahead.

Next I'll quickly cover our operational priorities for 2015. We expect to grow production by 2% to 3% from 2014 to 2015 and this includes an expected first quarter production rate of between 1.57 million and 1.61 million barrels per day. Walking through the segments, in Alaska we're focused on progressing our development drilling programs and major projects of CD-5 and drill site 2S. Both projects are expected to start up in the fourth quarter of this year. We intend to sanction the first phase of the Northeast West Sak development, the 1H NEWS project and we'll continue to progress a new rotary rig and new coiled tubing drilling rig to optimize our long-term development drilling inventory in Alaska. But we have decided to defer the final investment decision on the GMT1 project.

In the onshore Lower 48, unconventional activity will slow across the portfolio relative to 2014. We'll continue to evaluate pilot tests including the Upper Eagle Ford with our triple stack development concept. In the deepwater Gulf of Mexico we'll continue to appraise existing discoveries. We have wells drilling at Gila and Tiber right now and anticipate additional appraisal well drilling in Shenandoah later this year. In Canada we're reducing our conventional and unconventional development drilling activity. Oil sands production from Foster Creek F will continue to ramp up. Surmont 2 is on track for first steam in mid-2015 and we'll commence exploration drilling offshore Nova Scotia later this year.

In Europe, Ekofisk South and Eldfisk II continue to ramp up and we'll continue progress on the Enochdhu and Alder projects. In the Asia-Pacific and Middle East segment APLNG is on track for startup in the middle of the year. We're ramping up Gumusut in Malaysia and we're awaiting third-party pipeline repairs to allow production to ramp up at KBB, which we expect to start in the middle of the year. We'll also complete appraisal at the Barossa field, offshore Australia.

In our Other International segment we'll continue to monitor circumstances in Libya, evaluate result of our recent testing in Poland, begin appraisal work offshore Senegal and continue to execute our exploratory drilling programs in Angola and Colombia.

So we've got another busy year ahead of us and in any price environment, we're committed to safely executing our programs and delivering flexible growth while retaining high-value future options and inventory.

Now I'll turn the call back to Ryan for his closing remarks.

Ryan M. Lance

Chairman & Chief Executive Officer

Thank you, Matt. So let me recap what you've heard today. I think we delivered again in 2014. But certainly that was then; now it's all about 2015 and it's all about flexibility and resilience which we believe we have both.

Our priorities are clear: dividend and cash flow neutrality and we're taking immediate actions to defend them. We're cutting CapEx, capturing cost improvements and exercising our balance sheet if needed. And we're also thinking about the timeframe beyond 2015. We're asking ourselves, what's changed in our industry, if anything, for the longer term? We're testing our portfolio under different scenarios and again, we'll see that we have a resilient portfolio with flexibility to adapt if circumstances warrant.

Now some things might change. But here's what's not going to change. We're going to allocate capital prudently, we'll continue to migrate our portfolio to a lower cost of supply, we'll maintain capital and financial flexibility and we'll pay our shareholders first. That's our formula for creating long-term shareholder value. And I look forward to seeing you and describing that in more detail in April in New York. So with that, now let me turn the call back over to the operator and we'll take some Q&A.

QUESTION AND ANSWER SECTION

Operator: Thank you. We will now begin the question-and-answer session. [Operator Instructions]

And our first question is from Doug Leggate of Bank of America Merrill Lynch. Please go ahead.

Doug Leggate
Bank of America Merrill Lynch — Q

Good morning, everybody. Thanks for taking my questions. Folks, I wonder if I could dig into the cash flow neutrality question a little bit, because obviously the dividend is still a big commitment for you guys. When you separated Phillips, I think Jim, at the time, had talked about a maintenance capital level of around $10 billion to hold production flat. Well, I guess what I'm trying to understand is, to Matt's comment. Obviously that was $100 oil so one assumes that costs are going to drop at some point. But also had a slightly different portfolio and you've had a bunch of new projects come online that are longer life, or will come online, rather. So what is that number today, as it stands today and maybe assuming some cost reductions over time? And I've got a follow-up, please.

Matthew J. Fox
Executive Vice President-Exploration & Production — A

So I think, Doug, a number of $9 billion to $10 billion to keep production flat is a good go-by for now. I mean, clearly it's going to be a function of how much deflation we see, that's sustained deflation across the industry. But a number of that sort of magnitude is a good go-by for the time being.

Doug Leggate
Bank of America Merrill Lynch — Q

So when you talk about cash flow neutrality, I don't know if this is either Jeff or Matt, but what commodity deck are you assuming when you think about that for 2017?

Jeff W. Sheets
Chief Financial Officer & Executive Vice President — A

Like the comment that Matt made about capital, that also depends on what kind of cost deflation we see in both capital costs and operating costs. We don't expect that prices are going to maintain at current levels for that period of time, so we would be at cash flow neutrality at some improvement over current price levels but not at a level as high as what we've experienced recently.

Ryan M. Lance
Chairman & Chief Executive Officer — A

So, Doug, what I would say as we see a modestly rising price deck over the course of the next few years but certainly not back to a level that we've seen the last two or three years.

Doug Leggate
Bank of America Merrill Lynch — Q

Got it. My follow-up if I may, Ryan, it's probably one for you or it's really more of a high-level strategy question because we could debate over the years what the market looks for out of Conoco. Your unique offering obviously is the dividend but top line growth for a company of your size is always going to be relatively modest at best. So

when you think about the trade-off between portfolio high grading, bringing new projects on and perhaps monetizing or exiting other areas, with the potential to buy back shares when you do get a windfall of oil prices as we may have just had over the last several years, how do you see the strategic rationale of continuing to pursue top line growth in a volatile oil price environment as opposed to continue as high grading with a very strong yield and the option to buy back stock? I'm just kind of curious as to how this low oil price environment changes your thinking.

Ryan M. Lance
Chairman & Chief Executive Officer

A

Yeah. I think as I look out, we probably should expect with some of the modest growth that we're seeing in demand and really the resiliency that we see in the unconventionals having an impact on the supply, we're going to be in a more volatile world as we go ahead. So as I think about that strategically for the company, we're trying to build a company that has a solid base of legacy assets, low production decline, the things that you can underpin the dividend with over time. So as we bring on the oil sands our legacy assets in Alaska, what we're doing in Europe and the North Sea, what we're building in Asia-Pacific. And then on top of that, we're moving to a lower cost of supply in the portfolio through the addition of the unconventional portfolio that we're developing here in North America.

And that provides us a lot of resilience and flexibility to the capital. So we'll see what the commodity price gives us. We'll protect the dividend first and then with what's left over in the cash flow, we'll fund a capital program that will set the growth that we see coming out of that, because we know the growth is directly related to that capital program. When it comes to share buyback, we'll just assess what we have in terms of capital opportunities in the portfolio. If they're good, strong returns, which we think they're going to be with the unconventional inventory that we have, we'll judge that against the opportunity for share buyback down the road.

Operator: Thank you. Our next question is from Doug Terreson of Evercore ISI. Please go ahead.

Doug T. Terreson
International Strategy & Investment Group LLC

Q

Good morning, everybody.

Ryan M. Lance
Chairman & Chief Executive Officer

A

Good morning, Doug.

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Hi, Doug.

Doug T. Terreson
International Strategy & Investment Group LLC

Q

Ryan, one of your competitors indicated today that service calls have not declined as much as might be expected given the decline in oil and gas prices, and while there's always going to be lag effects and different contract durations and other things, I wanted to see if you would elaborate further on what ConocoPhillips has seen in the market and whether service cost lag effects were an important factor in today's reduction in spending or whether it was really lower prices. And then also some of the specific initiatives that you guys are undertaking that led to the $500 million benefit that you talked about a few minutes ago.

Ryan M. Lance
Chairman & Chief Executive Officer

A

Yeah. Sure, Doug. I can chime in and Matt's even closer to it than I am, so I can let him add some color to it if he would like. But yeah we've – so what we've said is we are seeing reductions as rigs start rolling off, onshore rig rates will be coming down. We're seeing pumping services and some of the commodities, and we're tracking each one of those. We have 20 different categories that we track on the supply chain side, and we're looking at them pretty closely. Now a lot of those are coming to the capital side, some go to the OpEx side. What we said is we've got pretty clear line of sight to the $500 million of reductions that we've factored in, but those are going to continue as this commodity price environment continues into 2015, and depending on the recovery that we see coming into 2016.

We're all over it. We're looking to try to capture as much of that as we can. The interesting sort of piece that you get, all the reductions and the flexibility that we're exercising is in North America, and that's where we expect to see a lot of the first reductions from capturing the deflation. So, I don't know, Matt – I think that's where – we're all over it, Doug, and we're going to get as much as we can out of it and as quickly as we can.

Doug T. Terreson
International Strategy & Investment Group LLC

Q

Sure. Okay. Well thanks a lot, guys.

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Thank you, Doug.

Ellen R. DeSanctis
VP-Investor Relations & Communications

A

Thanks, Doug.

Operator: Thank you. Our next question is from Scott Hanold of RBC Capital Markets. Please go ahead.

Scott Hanold
RBC Capital Markets LLC

Q

Thanks. I'd like to dig into the CapEx and flexibility just a little bit more, and you did cite your maintenance CapEx is around $9 billion to $10 billion. But when you step back and look at major project spend, as I think you cited, you're seeing a reduction in 2016, 2017. Can you give us a sense of what the size of that might be and how much you guys think you need to spend annually on those longer dated projects, whether you have them today or you need to build them for long-term growth opportunities?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Well as we move from 2015 into 2016, we'll see about $2 billion coming out of our major capital projects CapEx requirements just from Surmont and APLNG. So that's why we're referring to a significant increase in flexibility from 2015 to 2016, and that trend continues. There's several hundred million. It's not billions of barrels as we go from – billions of dollars as we go from 2016 to 2017, but that trend of reducing capital going to major projects and increasing capital going to the flexible low cost of supply and development programs, that's an underlying

part of the strategy that we've been executing for the past three years, and we're in the middle of that and an adjustment to our overall investment portfolio right now and for the next couple of years.

Scott Hanold
RBC Capital Markets LLC

Q

Okay. So if I can clarify, if I look at that $11.5 billion 2015 budget, call it you take out $2.5 billion for some of these major projects, and that gets you to somewhat that maintenance capital level?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

That's a good way of thinking about it. Yeah. That's close enough.

Scott Hanold
RBC Capital Markets LLC

Q

Okay. I appreciate that. And one follow-up question then. On your rig count reductions, obviously they're pretty meaningful in the U.S. onshore, and when you look at plays like the Bakken, the Eagle Ford and Permian, can you give us then when you're drilling your projects today, and you sit there and look at three, four, and six rig counts, do you assume that these will be economic at current spot prices, strip prices or a better price? And just to give you some context, I know there's a lot of debate whether or not the Bakken is economic today so why should there be any rigs drilling there today?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Yeah. So we're in the sweet spot of the Bakken. With the rig rates and the rates that we're getting, it's economic at current conditions, but we're actually taking that all the way down to a three rigs this year. We do have some commitments within some of the units in the Bakken where we have to run some rigs in the Bakken. The Eagle Ford is still very economic even at the current prices. But having said that, it makes more economic sense to defer. So what we're dealing with in the Eagle Ford is that a balance of -- we have some commitments. We need to run probably three rigs to meet commitments on our leasehold. We're also keen to continue to learn in the Eagle Ford because we have a huge inventory there that we could develop over the next couple of decades, and we want to make sure that we're capturing all the learnings.

So we're choosing to continue with some of our pilot tests as we go through 2015. And our expectation is, as some of the capital flexibility appears more into next year, that we're likely to increase our rig counts and take advantage of what may be higher prices but certainly will be deflated costs.

Operator: Thank you. Our next question is from John Herrlin of Societe Generale. Please go ahead.

John P. Herrlin
SG Americas Securities LLC

Q

Yes. Hi. Addressing the services costs another way, are you getting discounts from book rates? Or are you going to be able to get longer-term rates at discount or is it too early regarding fracking rigs, et cetera?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

So there's a mixture of both going on, John. I mean, this isn't a great time to enter any long-term commitments, until we see how the deflation works its way through the system, but we're working with the suppliers. We've got a great relationship with the suppliers and we're looking at across a spectrum of things, influence of capital and operating costs and making judgments every day on what the most prudent thing to do is in terms of contract duration and commitments against the reducing costs that we're seeing.

John P. Herrlin
SG Americas Securities LLC
Q

Okay. Thanks, Matt. One other question. Ryan, you said it's a more volatile world. Given the short cycle nature of shale-based activity, would you ever institute a hedging program in the shales, or just given your size it's not realistic?

Ryan M. Lance
Chairman & Chief Executive Officer
A

Yeah, I think the latter is the case, John. It's our size. We're naturally hedged a bunch across a lot of commodities in the markers. So given our size and where we're at, we don't see that as a useful strategy right now.

John P. Herrlin
SG Americas Securities LLC
Q

Great. Thank you.

Ellen R. DeSanctis
VP-Investor Relations & Communications
A

Thanks, John.

Operator: Thank you. Our next question is from Guy Baber of Simmons & Company. Please go ahead.

Guy A. Baber
Simmons & Co. International
Q

Good afternoon everybody.

Ryan M. Lance
Chairman & Chief Executive Officer
A

Hello, Guy.

Matthew J. Fox
Executive Vice President-Exploration & Production
A

Hi.

Guy A. Baber
Simmons & Co. International
Q

I had a question on your 2015 production and I was trying to get a better sense of the general trend as we progress through the year, especially for the U.S. unconventional portfolio. So could you help frame for us perhaps what kind of the 2015 exit rate production expectations might be for the Lower 48 on the current capital spending plan? And then any early expectations on 2016 with current rig count levels would be much appreciated, and then I have a follow-up.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Well, Guy, I think you're really trying to focus in on the unconventionals in our portfolio. So to give you a sense of that, we expect our production from the Eagle Ford and Bakken will grow from about 200,000 barrels a day in 2014 to about 225,000 barrels a day in 2015, so somewhere between a 10% and a 15% increase. That production growth is all going to come through the first half of the year. And then if we stay at the rig counts that we said just now, we're going to go into a slow decline in both the Bakken and Eagle Ford. Not a rapid decline, but a slow decline and that's going to continue into early 2016. So where our 2016 average rate will be is going to be a function of the number of rigs we decide to run. And as I said earlier, we do expect to increase our rigs in the Eagle Ford and Bakken in 2016. So production may be flat from 2015 to 2016 but time will tell. So growing production on average, year on year from 2014 to 2015, all of that growth is seen in the early part, in the first half of the year and then a slow decline through the third and fourth quarter.

Guy A. Baber
Simmons & Co. International

Q

That's very helpful, Matt. And then my follow-up, I wanted to kind of walk through some of the implications of the lower rig count. And you'd partially addressed this in your prepared comments, Matt, but how do you think about reduced investment levels materially but still retaining the practical ability to quickly flex those activity levels higher if the commodity price improves? And then secondly, can you just address, just with the focus on minimizing spending and maximizing efficiencies, your ability to still continue with some of your experimentation to drive long-term resource upside? I mean, are those plans still going to be in place in the Eagle Ford and the Bakken as well with the lower rig count? Any comments you could provide there would be great.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Yeah, so the organization that we have in the Lower 48 is flexible enough to bring the rigs down and bring the rigs back up if we want to do that. So that flexibility exists and we're exercising that flexibility now on the way down and we'll be ready to do it on the way back up again. So the organizational flexibility and the relationships with the suppliers and so on, that's all in-hand to go both ways. In terms of the continued experimentation, yeah, we have to choke back somewhat on the pace of learning. We can't do all of the pilot tests that we'd like to do, because you need to be drilling a lot of wells to do some of those. But the critical pilot tests that really have the biggest implications for a long-term resource understanding, we're going to continue with those sort of pilot tests through this downturn because of the implications of the value of that information for the long-term we think is worth continuing to collect.

Operator: Thank you. Our next question is from Blake Fernandez of Howard Weil. Please go ahead.

Blake M. Fernandez
Howard Weil, Inc.

Q

Hey, folks. Good morning. I have a question on slide seven. It looks like you provide the regional breakout of your adjusted earnings, and I hate to put too much emphasis on just one quarter, but it looks like the Lower 48 actually saw a loss compared to the other regions and obviously your cutting CapEx in the Lower 48 as well. I guess my view was that that was one of the main drivers of margin expansion going forward. So could you maybe elaborate a little bit on the economics that you're seeing there compared to the other investment opportunities that you have?

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Blake, in the Lower 48 in the fourth quarter, there were around $100 million or so of impairments that happened between, and then also some dry hole costs related to the Shenandoah appraisal well that we wrote off as well, which impacted that loss somewhat. But having said that, it will be a challenging year coming forward for Lower 48 based on the fact that there's still a fairly heavy natural gas waiting in the Lower 48 production. It is, as Matt mentioned, the economics are still there for continued investments that we're making, and those are good cash margin investments. But it is going to be a challenging 2015 at current commodity price levels in the Lo wer 48.

Blake M. Fernandez
Howard Weil, Inc.

Q

Sure. Understood. Okay. And then the second question is on the commitment to the dividend. I fully appreciate the differentiated strategy and having that as a top priority. But you mentioned debt to cap wou ld increase, and potentially investment grade could go below AA or A. Is there a level that we should think about where you begin to have to rethink that strategy and emphasis on the dividend, whether it be investment grade rating or a certain debt to cap level?

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

As we mention in our remarks on the calls, we look at a lot of different scenarios that might happen over the next couple years. We think between the capital flexibility that we have, the potential that we could have some level of asset sales in the mix, and the cash balance that we're starting with, that we don't think we're going to be having to face the question of having more borrowings than will take us out of that A credit r ating range. And again, that's part of the overall message here is that's baking in the dividend is the first priority for how we're using our cash flow.

Operator: Thank you. Our next question is from Paul Cheng of Barclays. Please go ahead.

Paul Y. Cheng
Barclays Capital, Inc.

Q

Hey, guys. Good afternoon. Couple quick questions, if I could. Maybe this is for Matt and Jeff. If you're looking at your supply cost, what percentage, how much of that supply cost is currently under contract longer than two years?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Supply costs, you mean like our rigs and so on?

Paul Y. Cheng
Barclays Capital, Inc.

Q

Yeah. Rig or anything that relate to your upstream operation.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Well in our North America business and certainly in Canada and the Lower 48 there's very, very little that extends beyond one year in terms of rig contracts. Most of them are 30 days. If we move out to the international business,

there are some in the UK and Alaska and Norway that are on longer-term contracts than that. But typically it's not common for us to have a significant amount of our drilling development-led portfolio constrained by long-term contracts.

Paul Y. Cheng
Barclays Capital, Inc.

Q

So, Matt, should we assume that more than 50% of your supply cost base that you could potentially start seeing cost reduction in a relatively quick timeline?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Oh, I see what you're getting at. You're looking at the opportunities to get deflation into that?

Paul Y. Cheng
Barclays Capital, Inc.

Q

That's correct. How quickly we would, because if you have a lot of your services under long-term contract and maybe be that you can negotiate even though that you're still under contract, but normally that people don't like you to allow that, but so that's why I'm trying to understand how quickly is that saving will be able to pass through?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

We're going to see it most quickly in the onshore North American business, and that's in particular in Canada and the Lower 48. We're not going to see it, for example, in the APLNG project. We're now almost 100% labor costs. We're not likely to see labor costs in Australia decrease over the next year. The same applies really to the Surmont 2 project in Canada where that's all labor just now, and we don't anticipate any significant labor cost reductions over the next few months as we complete the project. So the short answer is that the major projects are going to see limited and slower deflationary forces act on them in the development programs everywhere; but in particular, Canada and Lower 48 are going to see it more quickly.

Paul Y. Cheng
Barclays Capital, Inc.

Q

Okay. Second question, this is for Ryan. Ryan, I understand your priority in protecting dividend. What if, as the industry under stress and as a great opportunity arise and you have to make a choice between making an acquisition but that have to dramatically cut your dividend subsequently to ensure that you have sufficient cash flow going forward, how that choice will be made from your standpoint? I mean how you balance that?

Ryan M. Lance
Chairman & Chief Executive Officer

A

Well, Paul, it's an interesting scenario to try to think about but it's a tough one to pontificate a little bit over because we're focused on executing the plan that we have. We watch the M&A market, we see the assets that are out there. The issue with M&A and our portfolio is it's got to compete against investments that we have in the portfolio already today, and it's a pretty big hurdle for it to climb over. So I wouldn't speculate on where that might go.

Operator: Thank you. Our next question is from Ryan Todd of Deutsche Bank. Please go ahead.

Ryan Todd
Deutsche Bank Securities, Inc.

Q

Good, thanks. Good afternoon, gentlemen. Maybe one follow-up on activity levels and balance sheet. I guess as we look forward into 2016, implied on reaching the 2017 cash flow neutrality target even at the current CapEx balance and dividend rate would imply a relatively significant ramp in cash flow potentially from commodity prices into 2017 as is. So what would you need to see I guess in the market either from a cost or from a commodity point of view to actually start adding capital back to the budget as opposed to just letting things play out through 2017?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

So what we've said is that we're going to allow our capital to be flexible to manage within our cash flow and maintain the dividend. So the capital is going to flex and we have the portfolio to allow that to happen. So when we say that we're going to get to cash flow neutrality in 2017, there's a bunch of different ways that that could transpire. It could transpire through higher prices with more capital and more production or lower prices with less capital and less production growth. So we model all of these scenarios and we're planning to talk more about this, Ryan, when we have our Analyst Day in April.

Ryan M. Lance
Chairman & Chief Executive Officer

A

The capital, Ryan, is the flywheel. So again, we start with dividends being the number one priority. We'll fund that out of the cash flow. The growth will come from whatever capital level that we set, and the commodity price and the cash flow informs that and then we're setting that level to make sure that we reach cash flow neutrality by 2017. And as Matt said, across various scenarios of combination of capital and oil price projections, we're focused on getting there in 2017.

Ryan Todd
Deutsche Bank Securities, Inc.

Q

Great. I appreciate the lots of moving pieces in the equation. Just trying to get an idea if there is a level that you would think about that you would have to see at least to actually start putting some money back into the business incrementally from what you have now.

Ryan M. Lance
Chairman & Chief Executive Officer

A

We won't let cash flow neutrality move out beyond 2017, so I think that's the stake you can put in the ground, Ryan.

Ryan Todd
Deutsche Bank Securities, Inc.

Q

Okay. That's helpful.

Ryan M. Lance
Chairman & Chief Executive Officer

A

And it could move closer, depending on the commodity price levels and what the market gives us.

Ryan Todd
Deutsche Bank Securities, Inc.

Q

That's helpful. And then if I could ask on what you're seeing on the cost environment. I know you've talked a little bit. Am I correct in understanding that the vast majority of the $500 million CapEx cuts that you've implied in the budget to date have come in U.S.? And either way, can you talk a little bit – we have a little bit more visibility I think generally in what we see in the U.S., but can you talk a little bit about what you're seeing globally on costs across deepwater major capital projects, those type of things in the current environment?

Ryan M. Lance
Chairman & Chief Executive Officer

A

Well I think Matt's tried to address that. We see it'll be slower in the major projects, and those like APLNG and Surmont that have a large labor component, that's going to take a long time to work through the system depending on how long the down cycle is. We do see deepwater floater rigs coming off quite a bit, so the market today is quite a bit less than it was just a couple or a year ago, maybe this time a year ago. So we do see pieces of that. Tubular goods, oil country tubular goods, we see that coming down, and that's a commodity that we use across the world. So where we have development drilling programs and we use workovers and stuff, we see some of that flowing through as well. So it is a by category; it's different by each category, and it's different around the world. And the $500 million that we're talking about is something that we've got pretty clear line of sight on to capture this year, and that will continue into 2016.

Operator: Thank you. Our next question is from Edward Westlake of Credit Suisse. Please go ahead.

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

Yes. Good morning. A good discussion so far, and I'm going to have to stick with CapEx, then ask some smaller questions. Just on the $4.5 billion of major project spend, given that you do have APLNG, heavy oil, and some large projects in Malaysia that are going to finish hopefully at some point in 2015, it might be a help to ask to maybe give us some color as to, just on the existing projects, how might that look in 2016? Forget cost deflation but just the timing of the CapEx cycle.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

So roughly speaking, we're going to see – well let me give you some specifics. So APLNG will go from something like $1.6 billion this year to $0 next year. Surmont will go from about $800 million this year to about $250 million next year. There, so there's a [ph] few bins (50:44) are high-level and...

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

Yeah.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Views of those biggest projects. There are a few projects that are increasing in capital year-on-year. As the Clair Ridge project moves towards closure, we'll see a slight increase in capital there next year, and the same with the Malachi project in Malaysia. But overall, we're going to see something greater than $2 billion coming out of the –

in the mix between those larger, the biggest projects we're executing coming to an end, and some smaller projects that are already in execution ramping up a bit.

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

With the cash flow from those, and then that provides more confidence to add back rigs into shale? So I can see how that would...

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Well, actually you make a good point there, Ed, because one of the things about the projects like APLNG and Surmont, for example, is they'll start producing this year, but they won't actually get to peak rates for a full year until 2017. So they're going to be continuing to contribute to growth long after the capital's spent. As the Surmont project takes three years to ramp up, APLNG won't actually get to peak production until sometime early in 2016. The KBB project in Malaysia, we might only get half of year. Despite the fact that the project's complete, we're waiting on this pipeline being repaired. We might only get half a year of production from KBB this year, but we'll get a full year of production in 2015, and so on. So we're happy that these major projects are now getting to completion, not just because we don't have to spend the CapEx, but because now we're going to reap the reward over the next several years of contributing, growing our base production through these long-life – many of them long-life flat production projects.

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

But...

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

But to put a little bit more point on what Matt said as well, if you go back to our Analyst Presentation last April, we talked some numbers about how much cash we can expect to see coming out of APLNG and out of FCCL once those things are up and running, kind of at full rates by 2017. And those are lower numbers at lower commodity prices, but that's still a pretty significant source of cash for us, and that is an important part of the equation of getting to cash flow neutrality in 2017.

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

And just on APLNG though, just as a follow-up, how will you be treating I guess the CBM drilling costs? Would that be in CapEx or you put that in OpEx, just more of a modeling question? The maintenance CapEx on that project?

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Yeah, the...

Edward George Westlake
Credit Suisse Securities (USA) LLC (Broker)

Q

Which can be quite significant, I think.

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Yeah, because of the fact that APLNG is done with equity accounting for, I said, you don't end up seeing the capital expenditures for APLNG or the operating costs for it. You just see contributions in a current state. The contributions in are going in as capital and we'll just see distributions coming back out in the future.

Operator: Thank you. Our next question is from Alastair Syme of Citi. Please go ahead.

Alastair R. Syme
Citigroup Global Markets Ltd.

Q

Hello. I wonder if I could ask to what extent in this environment that OpEx and overhead might be the flywheel in terms of that cash neutrality. If you could put some granularity around the comments you made about G&A costs, it would be useful.

Matthew J. Fox
Executive Vice President-Exploration & Production

A

Yeah. And Alastair, yeah, we've talked a lot about capital, but we're equally focused on operating cost here as you'd expect. And just like we're focused across the whole value chain for capital deflation opportunities and capital, same thing's happening in operating costs. First of all, in costs that are externally driven like contract labor, materials and chemicals, and there's some price sensitivity to transportation costs and some of our transportation contracts. So we've got to look inside, too, for self-help reductions, looking at our internal operating costs and G&A. So we're already taking action there. We're going to have no salary increases in 2014. We've got a hiring freeze in place across most of the company. We've already announced plans to reduce head count in Europe that's quite significant. And we're likely to see more head count reductions in other parts of the business as we reassess the implications of lower prices on our future plans. So we have the whole company focused on minimizing our operating costs and we're not going to leave any stone unturned but we're not going to take any measures that reduce the safety or integrity of our assets.

And this is one of the things, Alastair, that we intend to talk about in more detail at the Analyst Day in April, our approach to the operating cost side of the accretion.

Alastair R. Syme
Citigroup Global Markets Ltd.

Q

Could you say how much of your operating cost of supply driven versus internal, what percentage? Roughly?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

I would say it's roughly 30% is internal, company labor, and then the rest is a mixture of transportation costs, contract labor, materials, parts. But about 30% is ConocoPhillips internal employee labor.

Alastair R. Syme
Citigroup Global Markets Ltd.

Q

Thank you very much.

Ellen R. DeSanctis
VP-Investor Relations & Communications

A

Thanks, Alastair.

Operator: Thank you. Our next question is from Roger Read of Wells Fargo. Please go ahead.

Roger D. Read
Wells Fargo Securities LLC

Q

Yeah, good morning.

Ryan M. Lance
Chairman & Chief Executive Officer

A

Hello, Roger.

Roger D. Read
Wells Fargo Securities LLC

Q

I guess coming at the OpEx question a slightly different way, we talked a lot about CapEx flexibility. As you think about the cash margin potential here, I mean, I think about the shale play, certainly where they were, probably a little more on the higher cash cost side, certainly looking across the industry. So as you pull back a little bit on your drilling there as we look at some of the projects and probably more of a 2016 than a 2015 impact from APLNG and Surmont, what do think about cash margins as you look into the latter part of 2015 and 2016?

Jeff W. Sheets
Chief Financial Officer & Executive Vice President

A

Well, we expect – the absolute level of the cash margin will come down with the commodity prices obviously, but as we look across the portfolio, most of the portfolio is quite resilient to – on a cash break-even basis, is pretty resilient to these prices. So as Matt said, were going to continue to drive operating cost reductions as well as the capital reductions, and while the absolute level of the margin will probably come down, we're still going to try to drive to see those margin improvements over the course of the next couple of years.

Roger D. Read
Wells Fargo Securities LLC

Q

Okay. Thanks. And then maybe a better question in April, but as you think about the exploration program here as part of the overall CapEx discipline and keeping the dividend in mind, flexibility obviously on the growth projects, what is the flexibility on exploration? And what is the maybe incentive here, as you mentioned, with lower rig rates to shift things out another six or 12 months where you can?

Matthew J. Fox
Executive Vice President-Exploration & Production

A

On the short-term aspect of that question in terms of the flexibility in our exploration spend, there's relatively limited flexibility in the short-term on our conventional exploration activity. We have rigs under contracts, we have agreements in place with governments and partners. So over the next year through 2015, that's why we haven't taken as much as you might expect out of exploration. We've really had to go through the parts of the exploration portfolio that are flexible. So we're going to find that 2015 is actually quite a big year for exploration in Angola, Senegal, Gulf of Mexico, Nova Scotia for example, and Australia. And so then there's a longer -term

question about the role of exploration in the growth of the company, and that's one of the things that we are going to talk about more in the Analyst Day in a couple of months.

Operator: Thank you. Our next question...

Ellen R. DeSanctis
VP-Investor Relations & Communications

A

Christine?

Operator: Yes?

Ellen R. DeSanctis
VP-Investor Relations & Communications

A

Sorry, Christine. I'm seeing it's the top of the hour we'll take one more question if you don't mind, okay?

Operator: Okay. Our last question is from Phil Gresh of JPMorgan. Please go ahead.

Phil M. Gresh
JPMorgan Securities LLC

Q

Hey, thanks for sneaking me in. Two quick ones. One is just the budget for this year. Is it fair to say that the $11.5 billion is set in stone at this point absent further deflation given that you have $2 billion rolling off into next year and that $9.5 billion is the core required to spend? So if you cut anymore this year it would be cutting into the meet-it so to speak?

Ryan M. Lance
Chairman & Chief Executive Officer

A

Yes, I think we've got to set the scope that we want to execute with the $11.5 billion. There is some certainty as to how much deflation we'll capture this year. We've added some in; it could be more than that. We're certainly trying to drive to more than that. But yes, we've set the scope associated with what we want to execute o n the $11.5 billion.

Phil M. Gresh
JPMorgan Securities LLC

Q

Got it. And then just a follow-up just on the asset sales topic, maybe any additional color you could provide around how you might approach a process like that. What parts of the portfolio might be something you'd want to monetize in this type of environment?

Ryan M. Lance
Chairman & Chief Executive Officer

A

Well, we continue to look. I've said we won't have another large announced asset disposition program, but you should expect us every year to be pruning the bottom part of the portfolio. Obviously it gets tougher in this kind of commodity price environment, but we set our new base case, we know what the assets are worth to us internally, and if there's interest out there in certain assets we'll entertain those and look at them. So I think you should expect some modest amount. It'll be tougher over the next couple of years, but there'll still be some pieces of our portfolio that we'll be taking a hard look at.

Phil M. Gresh
JPMorgan Securities LLC

Q

So you think you could get $500 million to $1 billion in cash a year out of asset sales? Any kind of target you're thinking about?

Ryan M. Lance
Chairman & Chief Executive Officer

A

I don't really have a target in mind. We'll do what makes sense.

Phil M. Gresh
JPMorgan Securities LLC

Q

Okay, okay. Fair enough. Thanks.

Ellen R. DeSanctis
VP-Investor Relations & Communications

Thanks, Phil. Okay, Christine, why don't you wrap it up here? Thanks, everybody, for your time, and by all means call IR if you have any other additional questions.

Operator: Thank you, and thank you, ladies and gentlemen. This concludes today's conference. Thank you for participating. You may now disconnect.

Exhibit 85

FOURTH-QUARTER 2014 | OPERATIONS REPORT | FEBRUARY 2, 2015

INVESTOR RELATIONS

John Colglazier
Senior Vice President
832/636-2306

Robin Fielder
Director
832/636-1462

Jeremy Smith
Director
832/636-1544

FOURTH-QUARTER 2014 AND FULL-YEAR HIGHLIGHTS

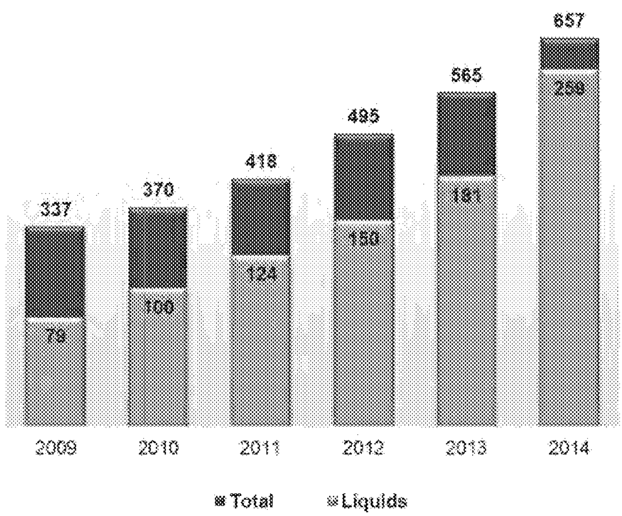
Anadarko

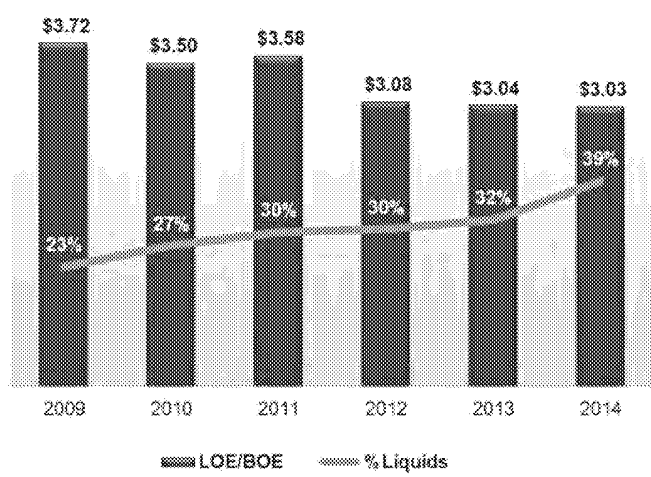
U.S. ONSHORE DRIVES GROWTH*

Anadarko's U.S. onshore achieved record sales volumes in the quarter, averaging 673,000 BOE/d, an increase of more than 82,000 BOE/d from the 4th quarter of 2013. Production in the Wattenberg field and Eagleford Shale drove U.S. onshore liquids growth, including a 52% year-over-year increase in oil volumes to approximately 165,000 BOPD in the 4th quarter.

For the full year, Anadarko's U.S. onshore assets delivered sales volumes of approximately 657,000 BOE/d, an increase of approximately 92,000 BOE/d over the prior year, equating to a 16% growth rate.

Since 2009, the U.S. onshore has grown total sales volumes by approximately 95%. The company has more than tripled liquid sales volumes over the same period while continuing to decrease its LOE per BOE.





*All volumes discussed exclude production associated with Pinedale/Jonah to provide a "same-store" sales comparison. "Same-store" sales volumes are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.

MONETIZATIONS ACCELERATE VALUE

In 2014, the company generated more than $2.5 billion from monetizations. Anadarko high-graded its Permian position in the 4th quarter by divesting more than 7,100 net non-core acres in the Midland Basin and used the proceeds to acquire nearly 10,000 net acres in the Delaware Basin adjacent to its core Wolfcamp Shale position.

MEGA-PROJECTS ADVANCE

Anadarko achieved first oil at its Lucius development in the 1st quarter of 2015, just over three years after sanction. The 80,000-BOPD facility is Anadarko's largest truss spar completed to date.

The 80,000-BOPD Heidelberg spar and TEN development also made significant progress during the quarter. The topsides of the Heidelberg spar are more than 70% complete, while the TEN development is approximately 50% complete. Both mega-projects are on track to achieve first oil in 2016.

The Mozambican government gazetted a Decree Law prior to year end. Also in the quarter, Anadarko and its partners continued to secure additional non-binding HOAs for long-term LNG sales, bringing total HOAs secured to more than 8 MMTPA.

Gas export from the Jubilee field in Ghana commenced in the quarter, which will enable increased oil production from the field in the future.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. While Anadarko believes that its expectations are based on reasonable assumptions as and when made, no assurance can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results, or other expectations expressed in this presentation, including Anadarko's ability to finalize year-end reserves, achieve its production targets, including anticipated growth rates, timely complete and commercially operate the projects and drilling prospects identified in this presentation, successfully plan, secure necessary government approvals, finance, build, and operate the necessary infrastructure and LNG park, and achieve its production and budget expectations on its mega projects. Other factors that could impact any forward-looking statements are described in "Risk Factors" in the company's 2013 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and other public filings and press releases. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

OVERVIEW

SALES VOLUMES*

Fourth-quarter sales volumes totaled a record 79 MMBOE, or 854,000 BOE/d, which was at the high end of quarterly guidance. The company reported liquids sales volumes of approximately 429,000 Bbl/d, 70% of which were oil.

Full-year divestiture-adjusted sales volumes averaged 838,000 BOE/d, an 11% increase over 2013.

CAPITAL

Fourth-quarter capital investments of $2.0 billion, which excludes capital investments associated with WES, were favorable to guidance.

For the full year, Anadarko capital investments of $8.44 billion were also favorable to guidance. This amount excludes $0.7 billion of capital investments incurred by WES and $123 million of property acquisitions.

Anadarko operated an average of 37 U.S. onshore rigs during the quarter which was a decrease of 19 rigs from the 4th quarter of 2013.

RESERVES

Anadarko replaced more than 160% of its production in 2014 by organically adding 503 million BOE of proved reserves, before the effects of price revisions, at competitive costs.

The company ended the year with estimated proved reserves of 2.86 billion BOE, with 69% being proved developed and comprised of 49% liquids.

SALES VOLUMES

	4Q14 Oil MBOPD	4Q14 NGLs MBbl/d	4Q14 Gas MMcf/d	4Q14 MMBOE	4Q13 Oil MBOPD	4Q13 NGLs MBbl/d	4Q13 Gas MMcf/d	4Q13 MMBOE
Rockies	108	59	1,221	34	70	43	1,227	29
Southern & Appalachia	57	54	1,149	28	38	47	1,126	25
Lower 48	**165**	**113**	**2,370**	**62**	**108**	**90**	**2,353**	**54**
Alaska	8	-	-	1	11	-	1	1
Gulf of Mexico	47	6	179	8	47	6	208	8
Total U.S.	**220**	**119**	**2,549**	**71**	**166**	**96**	**2,562**	**63**
International	80	10	-	8	90	-	-	8
Same-Store Sales	**300**	**129**	**2,549**	**79**	**256**	**96**	**2,562**	**71**
*Pinedale/Jonah & China***	-	-	-	-	9	4	81	3
Total Company	**300**	**129**	**2,549**	**79**	**265**	**100**	**2,643**	**74**

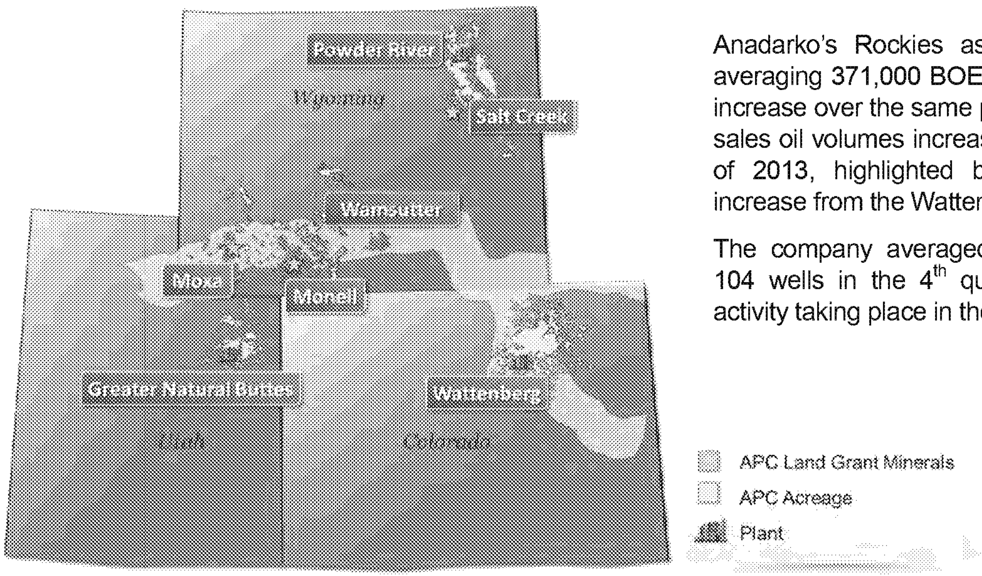
*All volumes discussed exclude production associated with Pinedale/Jonah and China to provide a "same-store" sales comparison. "Same-store" sales volumes are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.
**The Pinedale/Jonah divestiture closed in 1Q14, and the China Subsidiary divestiture closed in 3Q14.

CAPITAL INVESTMENTS

	4Q14 $MM
Rockies	746
Southern & Appalachia	712
Lower 48	**1,458**
Alaska	24
Gulf of Mexico	175
Total U.S.	**1,657**
International	157
*Midstream****	277
Capitalized Items/Other	78
Total Company	**2,169**

*** Includes WES capital investments of ~$206MM.

ROCKIES



Anadarko's Rockies assets delivered sales volumes averaging 371,000 BOE/d during the 4th quarter, a 17% increase over the same period in 2013. Total same-store sales oil volumes increased by 54% from the 4th quarter of 2013, highlighted by a more than 34,000-Bbl/d increase from the Wattenberg field.

The company averaged 13 operated rigs and drilled 104 wells in the 4th quarter, with the majority of the activity taking place in the liquids-rich Wattenberg field.

SALES VOLUMES								
	4Q14 Oil MBOPD	4Q14 NGLs MBbl/d	4Q14 Gas MMcf/d	4Q14 MBOE/d	4Q13 Oil MBOPD	4Q13 NGLs MBbl/d	4Q13 Gas MMcf/d	4Q13 MBOE/d
Wattenberg	85	43	400	195	51	19	278	116
Greater Natural Buttes	3	11	380	77	3	13	457	92
Powder River Basin	2	-	212	37	1	-	242	41
Wamsutter	2	5	108	25	2	7	113	28
EOR	14	-	1	14	13	-	1	13
Other	2	-	120	23	-	4	136	27
Same-Store Sales	**108**	**59**	**1,221**	**371**	**70**	**43**	**1,227**	**317**
*Pinedale/Jonah**	-	-	-	-	1	4	81	19
Total	**108**	**59**	**1,221**	**371**	**71**	**47**	**1,308**	**336**

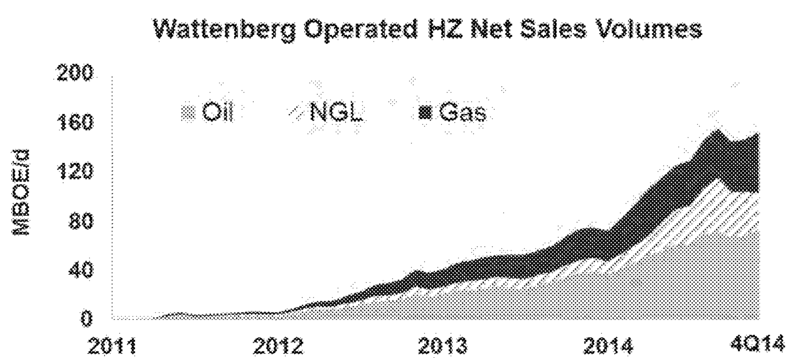
*The Pinedale/Jonah divestiture closed in 1Q14 .

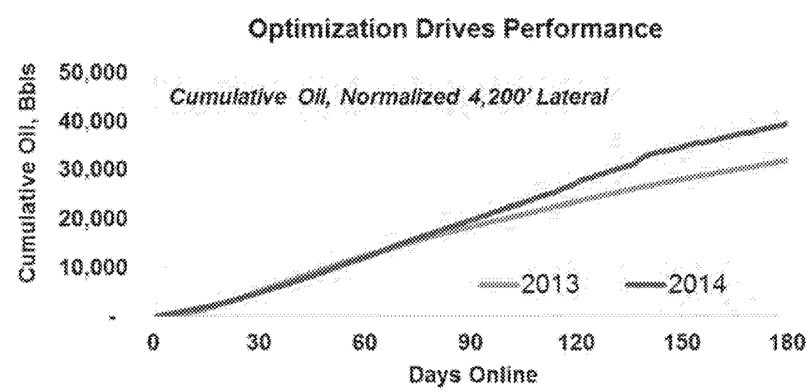
	CAPITAL INVESTMENTS 4Q14 $MM	AVERAGE RIG ACTIVITY 4Q14 Operated	AVERAGE RIG ACTIVITY 3Q14 Operated
Wattenberg	596	12	12
Greater Natural Buttes	30	1	1
Powder River Basin	22	-	-
Wamsutter	2	-	-
EOR	39	-	-
Other	57	-	-
Total	**746**	**13**	**13**

ROCKIES

Wattenberg:

- The Wattenberg field averaged approximately 195,000 BOE/d of net sales volumes during the 4th quarter, an increase of 78,000 BOE/d or 67% from the 4th quarter of 2013.
- The company operated an average of 12 horizontal rigs and drilled 82 wells (115 type-well equivalents) during the quarter.
- The company's operated horizontal program continued to deliver outstanding performance, averaging approximately 148,000 BOE/d, an increase of 126% from the 4th quarter of 2013. Anadarko's growth was supported by continued optimization of locations and drilling and completion techniques.
- To facilitate future growth, the company added 85 MMcf/d of field compression in the quarter, bringing the total field compression added in 2014 to more than 300 MMcf/d. The company expects to add approximately 200 MMcf/d of field compression in 2015 to maintain system pressures and keep pace with expected production increases.
- Construction continued on phase II of the Lancaster cryogenic plant in the quarter, including the setting of most of the major equipment and the demethanizer tower. The project was approximately 85% complete at year-end and is on track for commissioning in mid-2015.
- During the quarter, Lancaster entered ethane rejection, which, though reducing NGL yield, increased total product revenue.





ROCKIES

EOR:

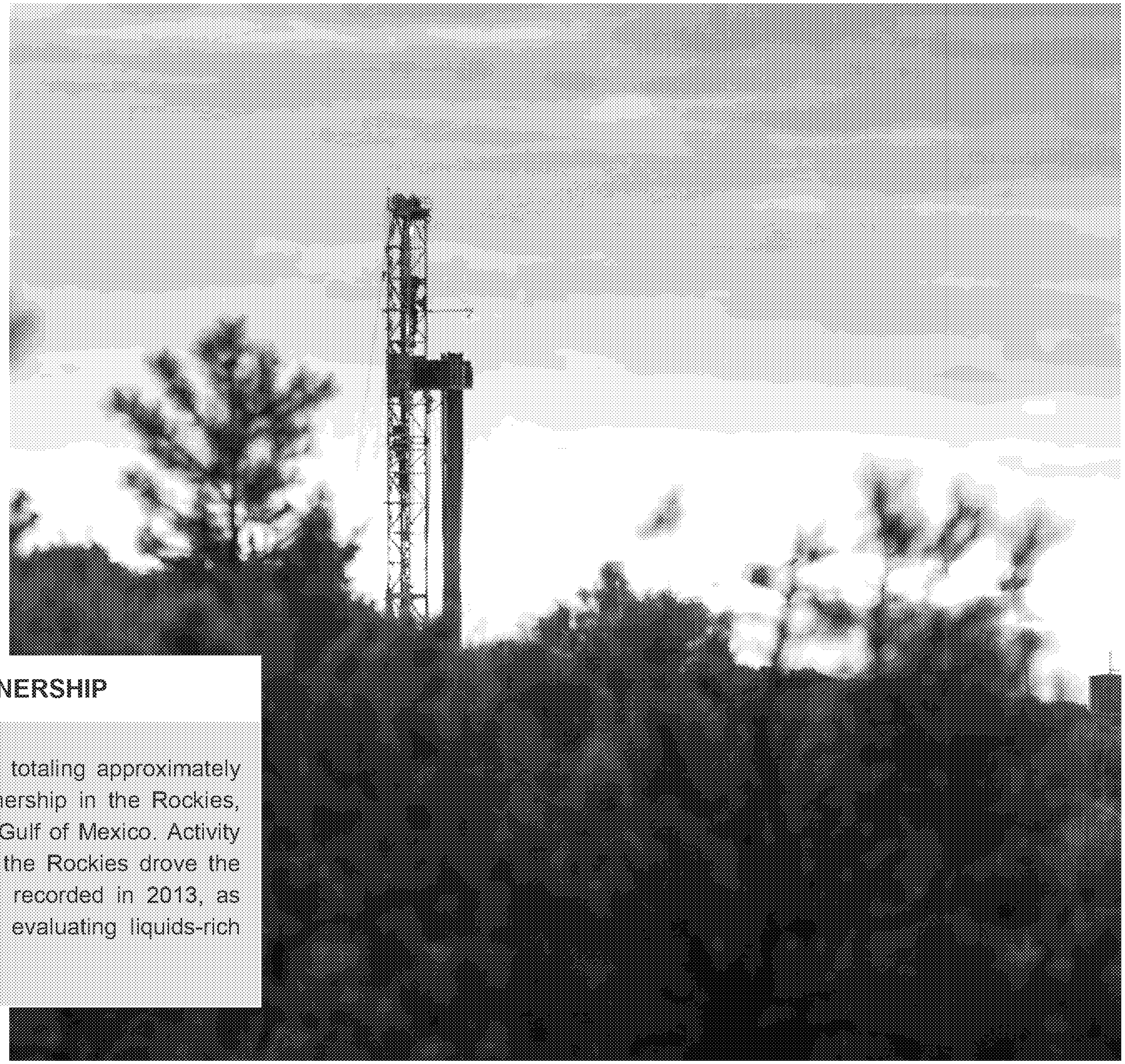
- Anadarko's EOR projects averaged approximately 14,000 BOPD in net sales volumes during the quarter, an increase of 9% from the 4th quarter of 2013.

Greater Natural Buttes:

- The company operated one rig in the quarter and drilled 20 wells.

Laramie County, Wyoming:

- Anadarko owns more than 100,000 mineral-interest acres in this emerging liquids-rich play.
- To date, the company has participated in more than 70 wells testing the Niobrara and Codell formations. Results from 19 producing wells remain strong with initial production rates averaging approximately 1,000 BOE/d.



MINERAL-INTEREST OWNERSHIP

In 2014, the company recorded revenues totaling approximately $775 million from its mineral-interest ownership in the Rockies, Southern & Appalachian regions and the Gulf of Mexico. Activity along Anadarko's Land Grant position in the Rockies drove the increase from approximately $675 million recorded in 2013, as Anadarko and other operators continued evaluating liquids-rich resource opportunities in the region.

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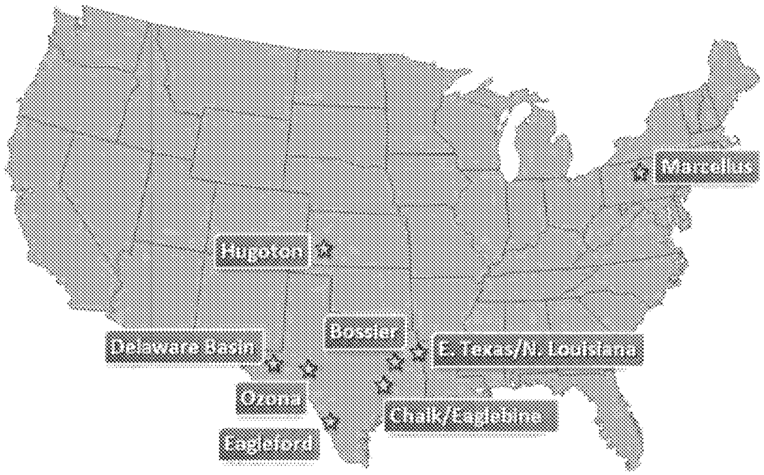
SOUTHERN & APPALACHIA



During the 4th quarter, the Southern & Appalachia region delivered sales volumes of approximately 302,000 BOE/d, an 11% increase from the 4th quarter of 2013. Total liquids volumes increased approximately 29% from the 4th quarter of 2013, highlighted by a more than 21,000-Bbl/d increase in the Eagleford Shale.

The company averaged 24 operated rigs and spud 141 wells in the quarter. In the region, company records were achieved in drilling, spud-to-rig-release times, cost-per-foot and water recycling.

SALES VOLUMES								
	4Q14 Oil MBOPD	4Q14 NGLs MBbl/d	4Q14 Gas MMcf/d	4Q14 MBOE/d	4Q13 Oil MBOPD	4Q13 NGLs MBbl/d	4Q13 Gas MMcf/d	4Q13 MBOE/d
Eagleford	33	25	143	82	19	18	99	54
Delaware Basin	14	5	49	27	9	4	42	20
E. Texas/N. Louisiana	2	17	240	60	2	18	233	59
Chalk/Eaglebine	6	3	21	12	5	3	24	12
Marcellus	-	-	546	91	-	-	565	94
Bossier	-	-	73	12	-	-	79	13
Hugoton	-	2	35	8	-	2	38	8
Ozona	-	2	22	6	-	2	24	6
Other	2	-	20	4	3	-	22	7
Total	**57**	**54**	**1,149**	**302**	**38**	**47**	**1,126**	**273**

	CAPITAL INVESTMENTS	AVERAGE RIG ACTIVITY	
	4Q14 $MM	4Q14 Operated	3Q14 Operated
Eagleford	246	8	8
Delaware Basin	338	9	9
E. Texas/N. Louisiana	67	5	5
Chalk/Eaglebine	8	1	1
Marcellus	31	1	1
Bossier	3	-	-
Hugoton	1	-	-
Ozona	1	-	-
Other	17	-	-
Total	**712**	**24**	**24**

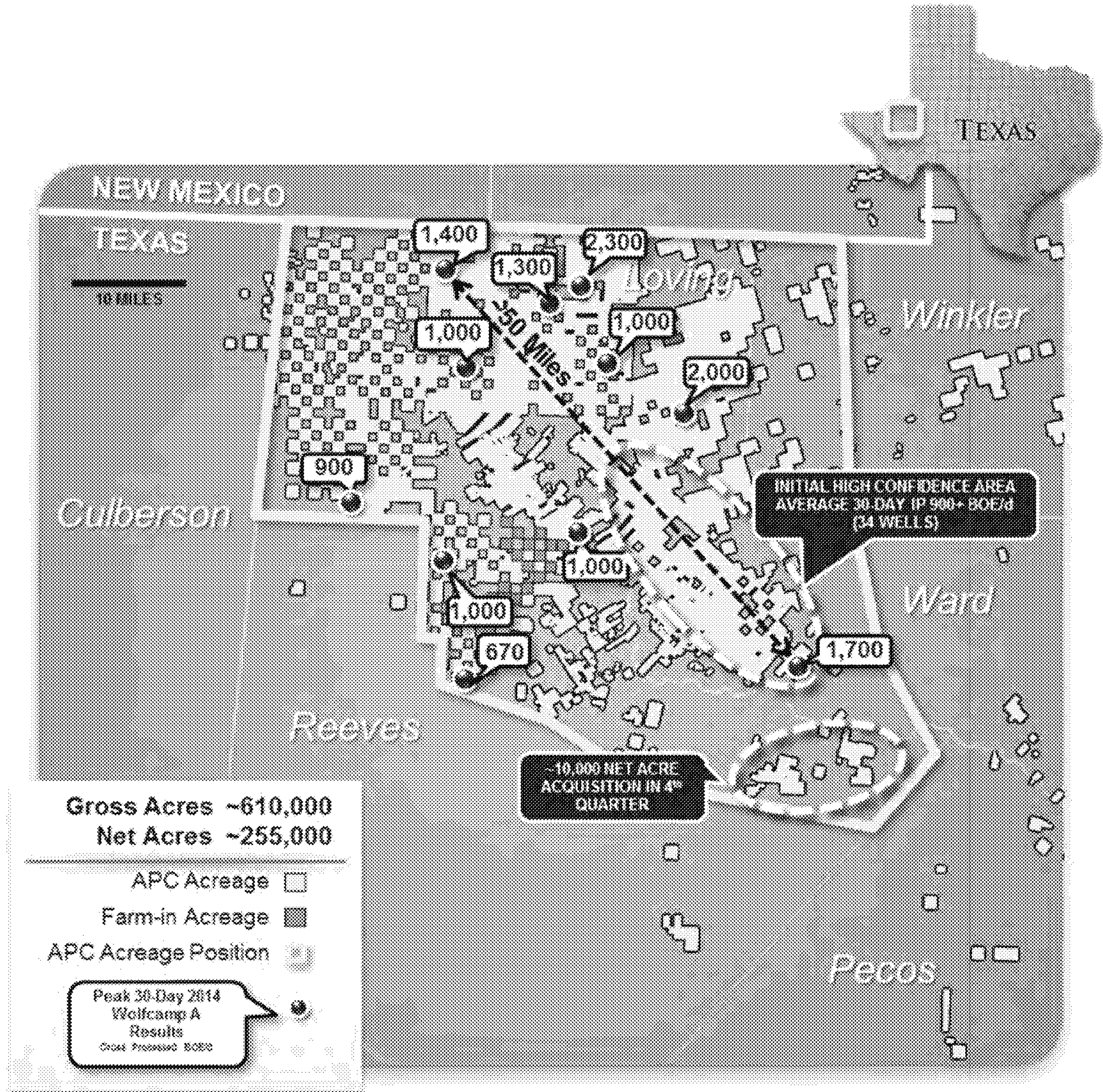
SOUTHERN & APPALACHIA

Delaware Basin:

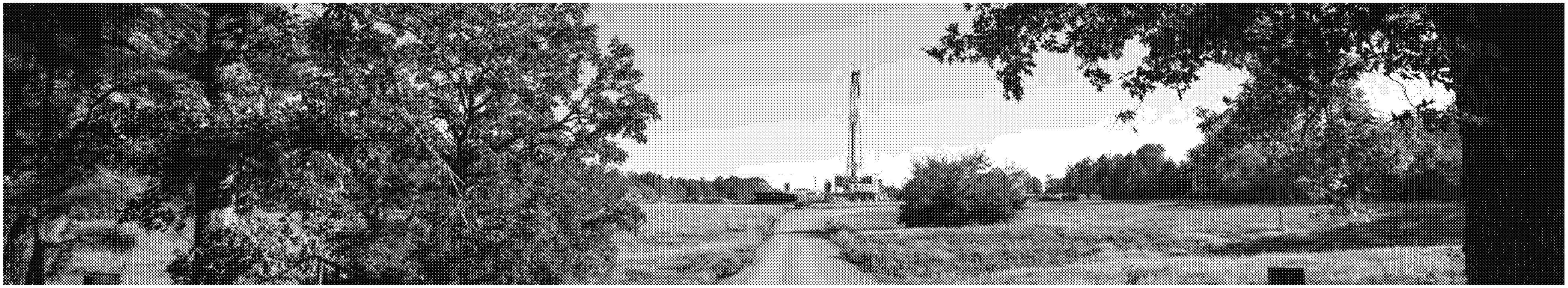
- Anadarko's net sales volumes for the quarter averaged approximately 27,000 BOE/d, a 33% increase from the 4th quarter of 2013. Total liquids volumes averaged nearly 19,000 Bbl/d, a 42% increase from the 4th quarter of 2013.
- The company averaged nine operated rigs in the Delaware Basin in the quarter.
- Anadarko continued to evaluate its Wolfcamp Shale position in the quarter. In 2014, the company spud 83 Wolfcamp Shale wells and brought 32 wells on line.
- The company expanded its leasehold in the basin during the quarter with the acquisition of 10,000 net acres in the southeast portion of its Wolfcamp Shale position.
- To date, Anadarko has recycled nearly 2 million barrels of produced water for use in its completion operations and is continuing to expand its water infrastructure and recycling programs in line with development.
- Following WES's closing of the Nuevo Midstream acquisition in the quarter, Anadarko began integrating its operated midstream assets to facilitate future development activities.

Eaglebine:

- Sales volumes in the quarter averaged more than 2,300 BOE/d, an increase of 334% from the 4th quarter of 2013.
- The company averaged one operated rig during the quarter.



SOUTHERN & APPALACHIA



Eagleford:

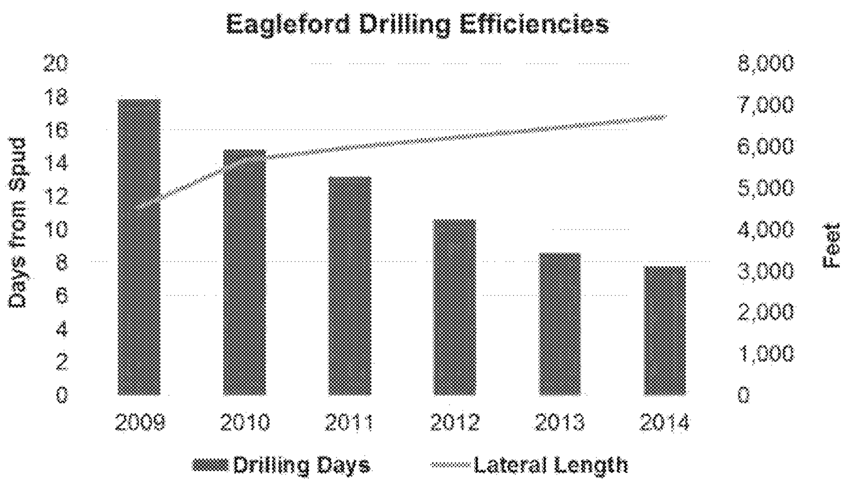
- During the quarter, the company achieved a gross-processed-production record of 250,000 BOE/d. Anadarko's net sales volumes averaged approximately 82,000 BOE/d in the quarter, a 54% increase from the 4th quarter of 2013. Total liquids volumes averaged more than 58,000 Bbl/d, a 58% increase from the 4th quarter of 2013.
- The company spud 87 wells utilizing eight operated rigs and brought 88 wells on line in the quarter.
- The company continued its focus on efficiencies in the Eagleford, reducing drilling-cycle times to 7.6 days from 8.4 days in the 4th quarter of 2013 and reducing the cost-per-foot to an all-time low of $89.

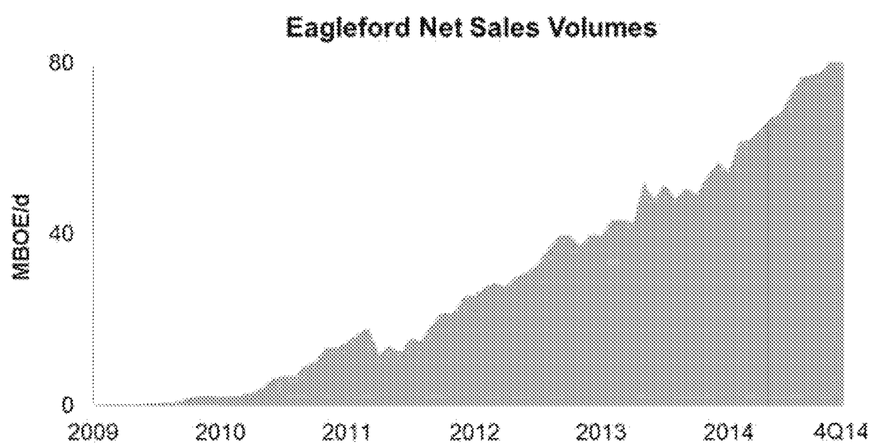
East Texas/North Louisiana:

- The company's net sales volumes averaged approximately 60,000 BOE/d. Total liquids sales volumes averaged approximately 20,000 Bbl/d.
- The company averaged five operated rigs and brought 12 wells on line in the quarter.

Marcellus:

- The company achieved a gross-operated production record of 699 MMcf/d in the quarter.





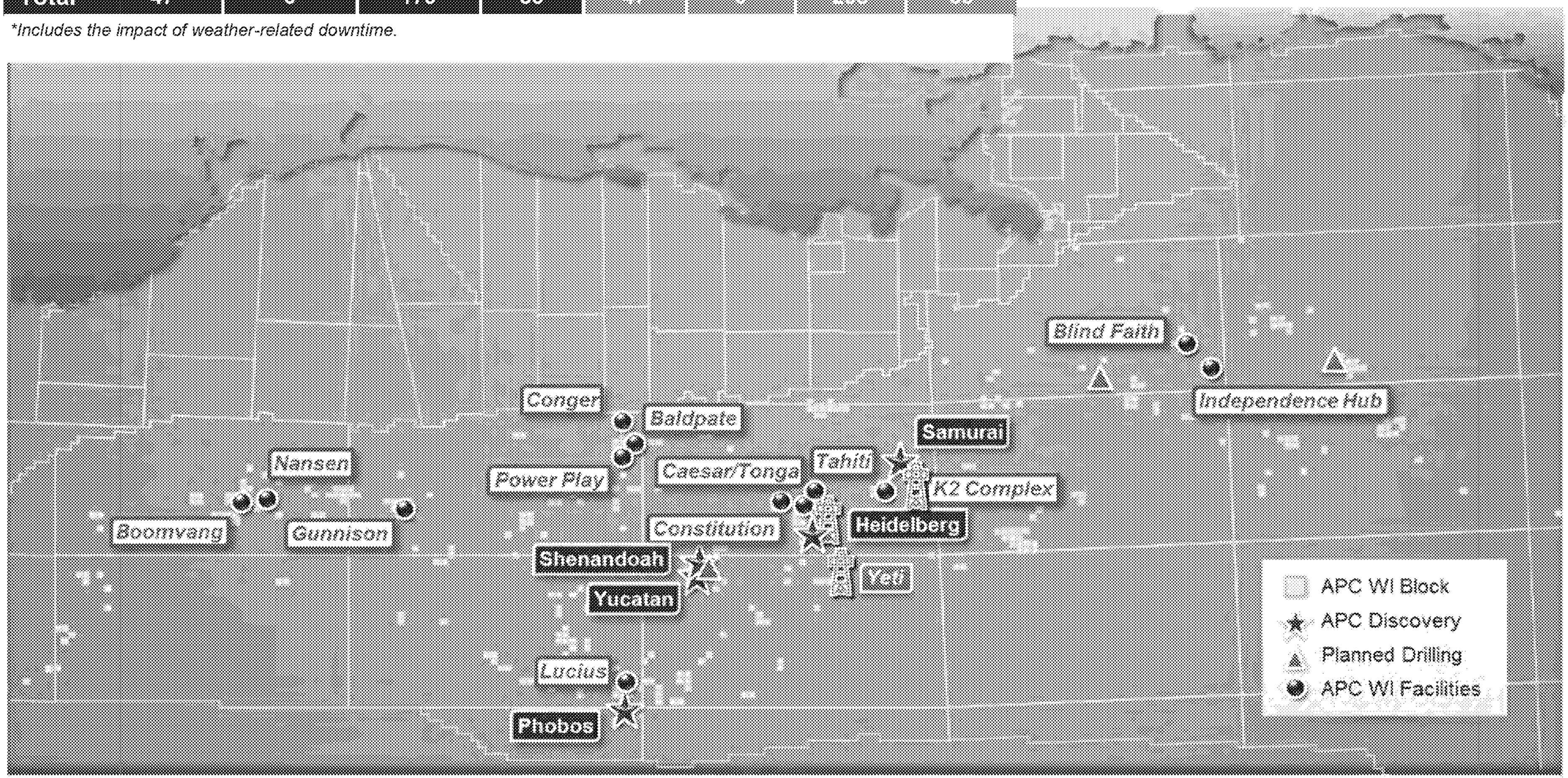
GULF OF MEXICO

During the 4th quarter, Anadarko's Gulf of Mexico region averaged sales volumes of approximately 83,000 BOE/d, approximately 64% of which were high-margin liquids.

SALES VOLUMES*

	4Q14 Oil MBOPD	4Q14 NGLs MBbl/d	4Q14 Gas MMcf/d	4Q14 MBOE/d	4Q13 Oil MBOPD	4Q13 NGLs MBbl/d	4Q13 Gas MMcf/d	4Q13 MBOE/d
Total	47	6	179	83	47	6	208	88

**Includes the impact of weather-related downtime.*



GULF OF MEXICO

DEVELOPMENT

Lucius:

KEATHLEY CANYON 874/875/918/919 (APC WI 23.8%)

- Lucius achieved first oil from the first of six initial development wells in the 1st quarter of 2015. The fabrication and installation of Lucius required more than 10.5 million man hours, which was achieved with industry-leading safety performance. At peak construction, more than 560 workers were involved in installing and commissioning the facility offshore.
- The company will continue to ramp production towards facility capacity.

Caesar/Tonga:

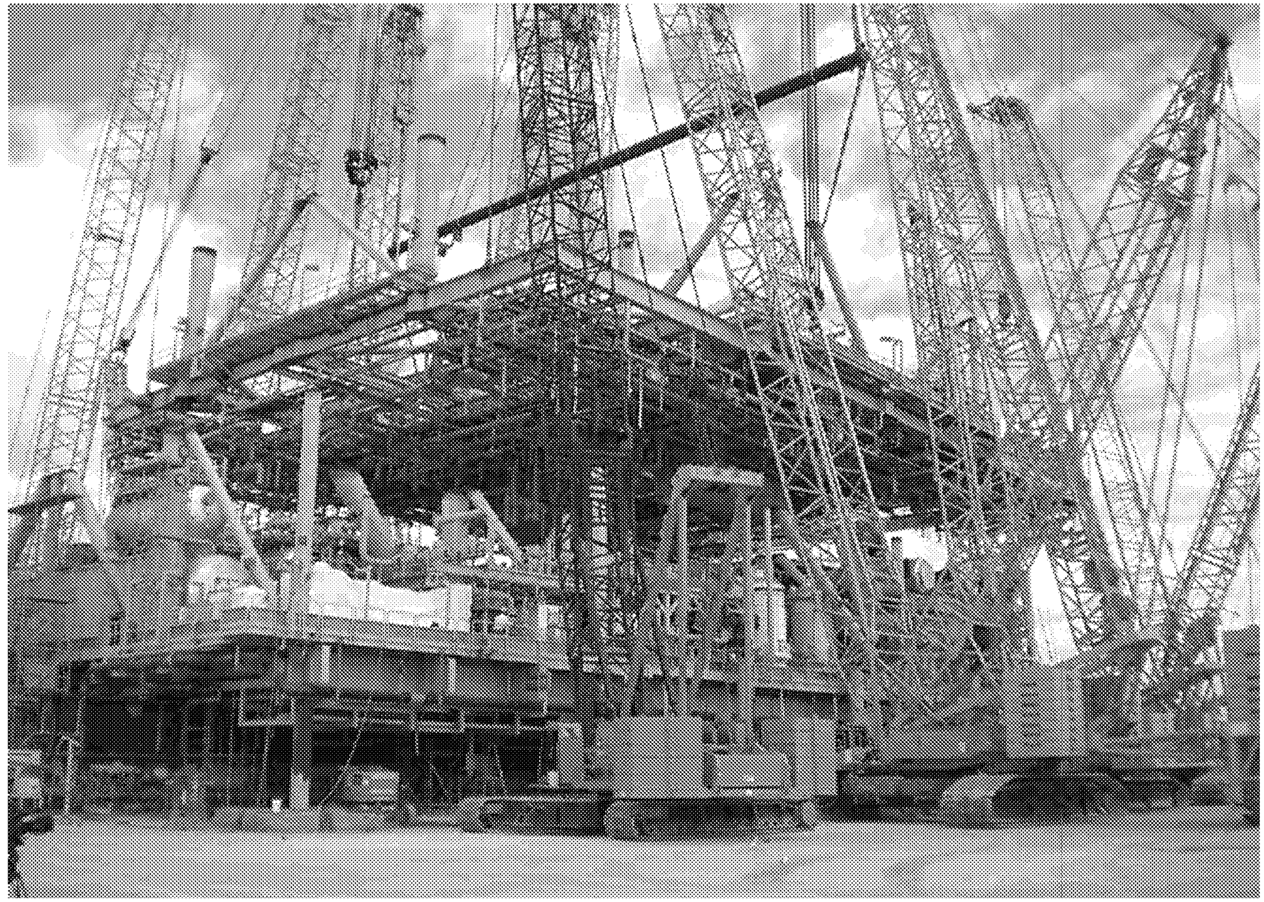
GREEN CANYON 683/726/727/770 (APC WI 33.75%)

- During the quarter, completion operations continued on the fifth Caesar/Tonga well, which is expected to be brought on line in the 1st quarter of 2015.
- A sixth Caesar/Tonga infill well is scheduled to spud in the first half of 2015.

Heidelberg:

GREEN CANYON 859/860/903/904/948 (APC WI 31.5%)

- Heidelberg remains on track for first oil in 2016.
- Fabrication of the main topsides module is currently ahead of schedule and was more than 70% complete at the close of the quarter.
- The drilling of two development wells continued in the quarter, while installation operations for flowlines, export lines and suction piles commenced.



Heidelberg Topsides Construction, Ingleside, Texas

K2 Complex:

- The company expects to begin sidetrack operations on the GC 562 #5 into an up-dip Miocene target in the 1st quarter of 2015. Production is expected in the second half of 2015.

Independence Hub:

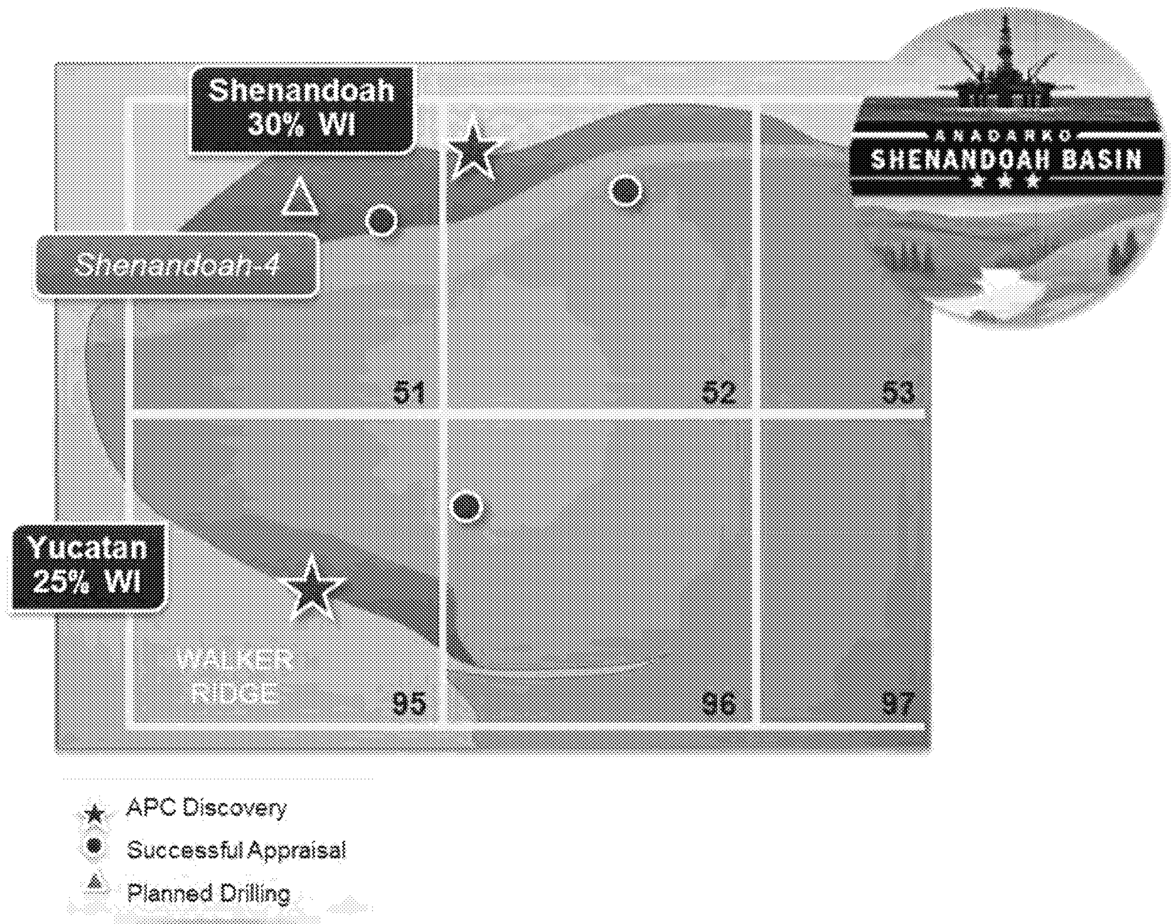
- Net production averaged 101 MMcf/d during the quarter.

EXPLORATION/APPRAISAL

Shenandoah:

WALKER RIDGE 51, 52 AND 53 (APC WI 30%, OPERATOR)

- Drilling of the second Shenandoah appraisal well, Shenandoah-3, concluded in the quarter. The Shenandoah-3 well found approximately 50% (1,470 feet) more of the same well-developed reservoir sands 1,500 feet down-dip and 2.3 miles east of the Shenandoah-2 well, which encountered more than 1,000 feet of net oil pay in excellent quality, Lower Tertiary-aged sands. The Shenandoah-3 well confirmed the sand depositional environment, lateral sand continuity, reservoir qualities and down-dip thickening. The well also enabled the projection of oil/ water contacts based on pressure data, and reduced the uncertainty of the resource range.
- Planning is currently underway for the next appraisal well, which the company expects to spud in the 2nd quarter of 2015.



Yeti:

WALKER RIDGE 117, 157, 158, 159, 160 (APC WI 37.5%)

- The Yeti exploration well was spud prior to year end. The well is in approximately 5,890 feet of water in Walker Ridge block 160 and is currently drilling toward a total vertical depth of 25,575 feet. The well will test a Miocene, sub-salt, three-way closure approximately 20-miles southeast of Anadarko's operated Heidelberg development.

INTERNATIONAL & FRONTIER

El Merk in Algeria

During the 4th quarter, the International and Frontier region sales volumes averaged approximately 98,000 Bbl/d.

The Mozambican government gazetted a Decree Law in the quarter, while additional non-binding HOAs for long-term LNG sales were reached prior to year-end.

SALES VOLUMES

	4Q14 MBbl/d	4Q13 MBbl/d
Alaska	8	11
*Algeria**	80	62
Brazil	-	-
*Ghana/W. Africa**	10	28
Mozambique	-	-
Other	-	-
Same-Store Sales	98	**101**
*China**	-	8
Total	**98**	**109**

**Quarterly sales volumes are influenced by size, timing and scheduling of tanker liftings.*

CAPITAL INVESTMENTS

	4Q14 $MM
Alaska	24
Algeria	18
Brazil	1
Ghana/W. Africa	50
Mozambique	87
Other	1
Total	**181**

DEVELOPMENT

Alaska:

- Gross production from the Colville River Unit averaged approximately 39,000 BOPD during the quarter. A drilling rig is continuing to work in the Alpine field on an extension well to the southwest.

Algeria:

- In the quarter, Algeria gross production averaged approximately 386,000 BOE/d as the El Merk facility continued to produce at plateau rates.

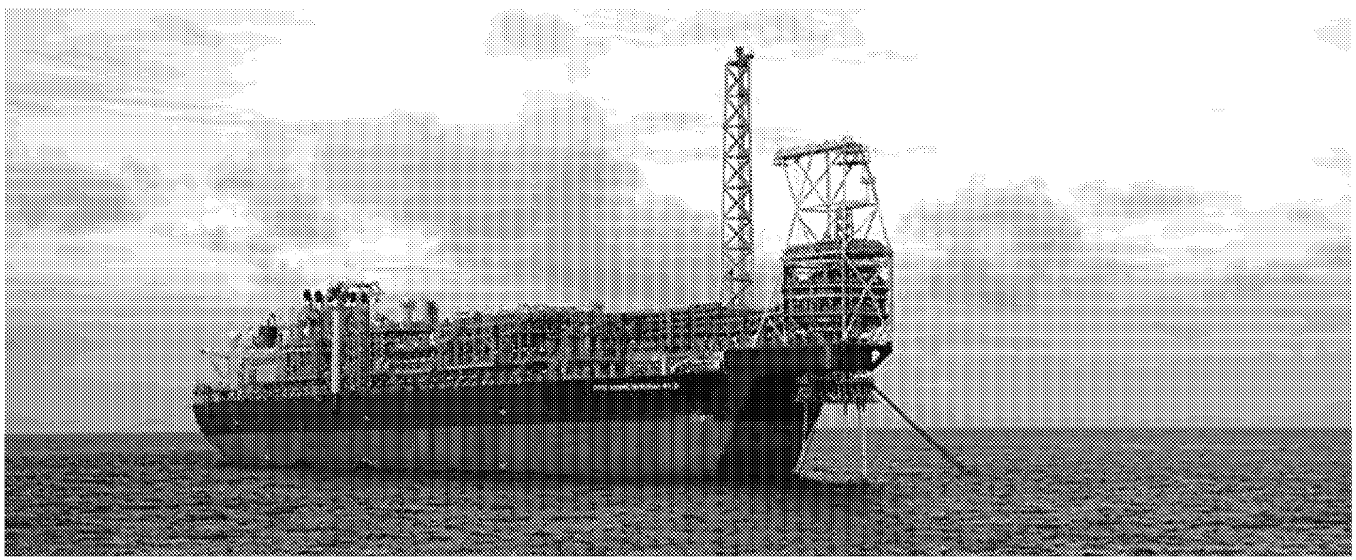
Ghana:

- Gross production at the Jubilee field averaged approximately 100,000 BOPD during the quarter. Gas export commenced in November, and commissioning of the onshore natural gas processing facility is ongoing. In 2015, gas export is expected to increase enabling oil production from the field to rise towards field plateau.
- Construction on the TEN development was approximately 50% complete at the close of the quarter. The 80,000-BOPD project remains on schedule for first oil in mid 2016. The partnership was drilling the last of the initial ten development wells in the quarter.

Mozambique:

OFFSHORE AREA 1 (APC WI 26.5%, OPERATOR)

- In December, the Mozambican government gazetted a Decree Law. This marked an important step toward establishing a project-wide legal and contractual framework that is expected to deliver a level of stability enabling continued equity investments by the partnership and potential access to significant, limited-recourse project finance capital.
- Additional non-binding HOAs for long-term LNG sales were reached in the quarter, bringing the cumulative total to more than 8 MMTPA at year end.
- Significant progress was made in the receipt of letters-of-intent for financial support from potential lenders.
- The partnership continued the evaluation of onshore LNG contractor bids during the quarter in preparation for contractor selection in 2015.



Jubilee Field in Ghana

EXPLORATION/APPRAISAL

Colombia:

FUERTE NORTE, FUERTE SUR, PURPLE ANGEL, COL 5 AND URA 4 (APC WI 50%, OPERATOR)

- Anadarko's two initial prospects have been selected for the 2015 exploration program offshore Colombia. The Calasu prospect is a large four-way structure on the north end of the block complex. It will have multiple potential targets and, with success, would de-risk several adjacent structures on the block. The Kronos prospect is located in the southern area of the block complex and will test a large structure associated with the frontal area of a large thrust complex. As with Calasu, success here would de-risk multiple identified prospects.
- The Bolette Dolphin drillship was mobilized to Colombia in the quarter. Once the drillship arrives, it will topset the Kronos well and then begin operations on the Calasu prospect.

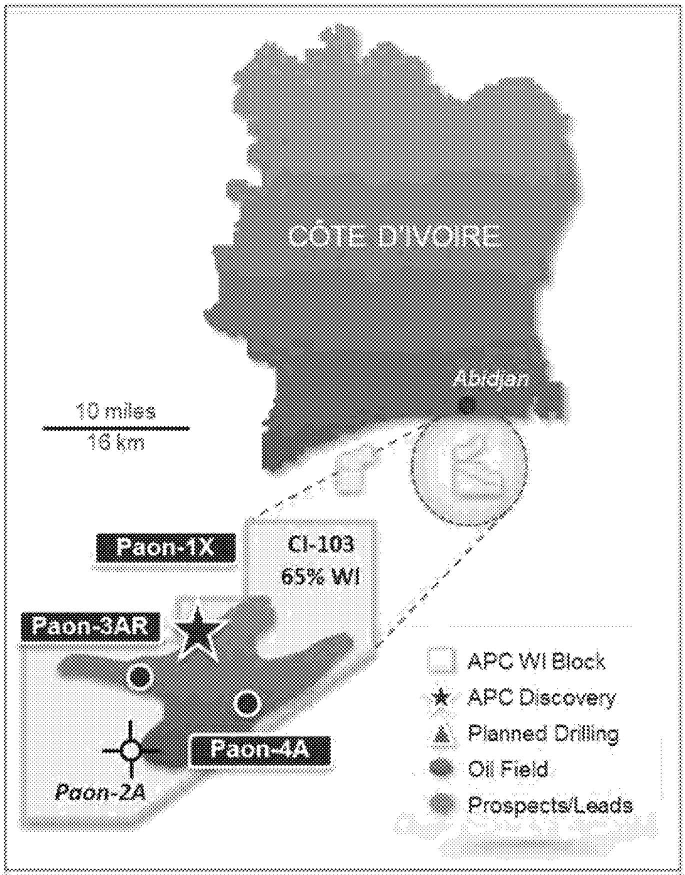
Côte d'Ivoire:

BLOCK CI-103 (APC WI 65%, OPERATOR)

- During the quarter, drilling results of the Paon discovery continued to be encouraging. The Paon-3AR was drilled 3.7-miles down-dip to the discovery well and encountered more than 94 feet of pay. The well established an oil/water contact and appears to be in communication with the Paon-1X. As a result of the success, the drilling of the Paon-4A was accelerated. The well, located six miles east of the Paon-3AR, penetrated more than 37 feet of pay in the target section and defined the eastern extent of the reservoir. Based on the successful drilling program to date, the partnership and the government are currently discussing additional appraisal drilling activity for 2015, which would include a drill stem test.

BLOCK CI-515 (APC WI 45%, OPERATOR)

- During the 4th quarter, the Saumon prospect was drilled to test a well-developed Cretaceous sand system trapped against a basin margin fault. Although thick, high-quality sands were encountered in the target interval, the well did not encounter hydrocarbons.



Côte d'Ivoire 4th Quarter 2014 Drilling Activity

Mozambique:

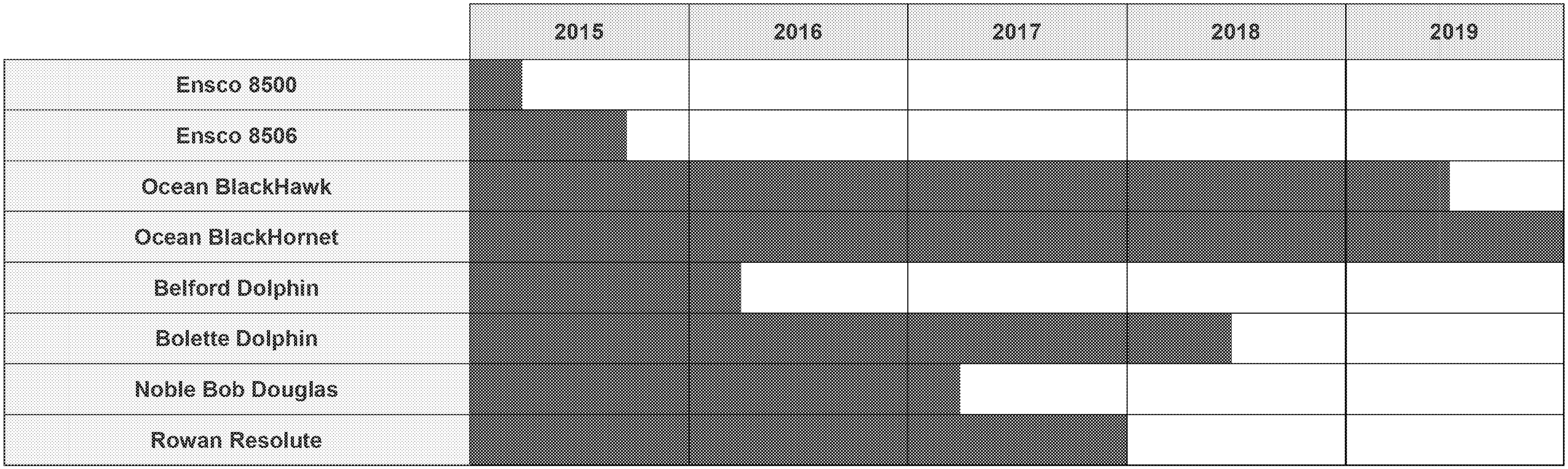
OFFSHORE AREA 1 (APC WI 26.5%, OPERATOR)

- Appraisal activity continued on the Orca discovery during the quarter. The Orca #4 well was completed and encountered natural gas pay in two reservoirs. Further analysis is under way to define future appraisal needs as well as a potential optimum development scenario.
- The Tubarão Tigre #2 was drilling at the close of the quarter. This is the first appraisal well to the 2014 discovery.

ONSHORE ROVUMA (APC WI 35.7%, OPERATOR)

- During the quarter, the company completed the Tembo well and evaluation operations. The well encountered natural gas and condensate in one of the Cretaceous reservoirs. Post-drill evaluations are under way to determine if additional exploration activity is warranted within the prospect area.
- The second well in the program, the Kifaru prospect, was spud in the 1st quarter of 2015. Kifaru will test Miocene, Oligocene and Paleocene natural gas targets near the future site of Anadarko's planned LNG facility.

DEEPWATER RIG SCHEDULE



Ocean BlackHornet Drillship

Bolette Dolphin Drillship

GLOSSARY OF ABBREVIATIONS

- **APC:** Anadarko Petroleum Corporation
- **Bbl:** Barrels
- **Bbl/d:** Barrels of Liquids per Day
- **BOE:** Barrels of Oil Equivalent
- **BOE/d:** Barrels of Oil Equivalent per Day
- **BOPD:** Barrels of Oil per Day
- **EOR:** Enhanced Oil Recovery
- **HOA:** Heads of Agreement
- **HZ:** Horizontal
- **IP:** Initial Production
- **LOE:** Lease Operating Expense
- **LNG:** Liquefied Natural Gas
- **MBbl/d:** Thousand Barrels per Day
- **MBOE/d:** Thousand Barrels of Oil Equivalent per Day
- **MBOPD:** Thousand Barrels of Oil per Day
- **MM:** Million
- **MMBOE:** Million Barrels of Oil Equivalent
- **MMTPA:** Million Tonnes Per Annum
- **MMcf:** Million Cubic Feet
- **MMcf/d:** Million Cubic Feet per Day
- **NGL:** Natural Gas Liquid
- **TEN:** Tweneboa, Enyenra and Ntomme
- **WES:** Western Gas Partners, LP (NYSE: WES)
- **WI:** Working Interest

Exhibit 86

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Company:	ANADARKO PETROLEUM CORP
Document:	10-K (FY 2014) · 02/20/2015
Section:	Entire Document
File Number:	001-08968
Pages:	165

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2014

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2014, was $55.3 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at January 30, 2015, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	506,650,285

Documents Incorporated By Reference

Portions of the Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 12, 2015 (to be filed with the Securities and Exchange Commission prior to April 2, 2015), are incorporated by reference into Part III of this Form 10-K.

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PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 2.9 billion barrels of oil equivalent (BOE) of proved reserves at December 31, 2014. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko's asset portfolio is aimed at delivering long-term value to stakeholders by combining a large inventory of development opportunities in the U.S. onshore with high-potential worldwide offshore exploration and development activities.

Anadarko's asset portfolio includes U.S. onshore resource plays in the Rocky Mountains area, the southern United States, the Appalachian basin, and Alaska. The Company is also among the largest independent producers in the deepwater Gulf of Mexico, and has exploration and production activities worldwide, including activities in Mozambique, Algeria, Ghana, Brazil, Colombia, Côte d'Ivoire, Kenya, Liberia, New Zealand, and other countries.

Anadarko is committed to producing energy in a manner that protects the environment and public health. Anadarko's focus is to deliver resources to the world while upholding the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko's business segments are managed separately due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are as follows:

Oil and gas exploration and production-This segment explores for and produces natural gas, oil, condensate, and natural gas liquids (NGLs), and plans for the development and operation of the Company's liquefied natural gas (LNG) project.

Midstream-This segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The Company owns and operates gathering, processing, treating, and transportation systems in the United States for natural gas, oil, and NGLs.

Marketing-This segment sells much of Anadarko's oil, natural-gas, and NGLs production, as well as third-party purchased volumes. The Company actively markets oil, natural gas, and NGLs in the United States; oil and NGLs internationally; and the anticipated LNG production from Mozambique.

Unless the context otherwise requires, the terms "Anadarko" or "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See *Risk Factors* under Item 1A of this Form 10-K.

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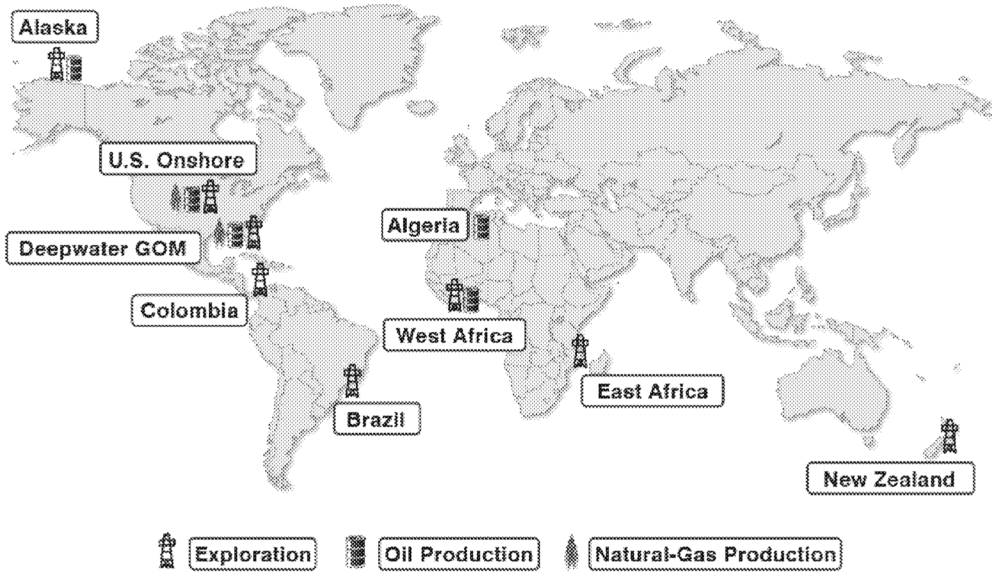
Available Information The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. The Company files or furnishes Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, registration statements, or any amendments thereto, and other reports and filings with the Securities and Exchange Commission (SEC). Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, by selecting SEC Filings on its website located at www.anadarko.com. The Company will also make available to any stockholder, without charge, printed copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this report or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330 or call (855) 820-6605, send an email to investor@anadarko.com, or complete an information request on the Company's website at www.anadarko.com, by selecting Investors/Shareholder Resources/Shareholder Services.

The public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reading Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reading Room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, like Anadarko, that file electronically with the SEC.

OIL AND GAS PROPERTIES AND ACTIVITIES

The map below illustrates the locations of Anadarko's oil and natural-gas exploration and production operations.



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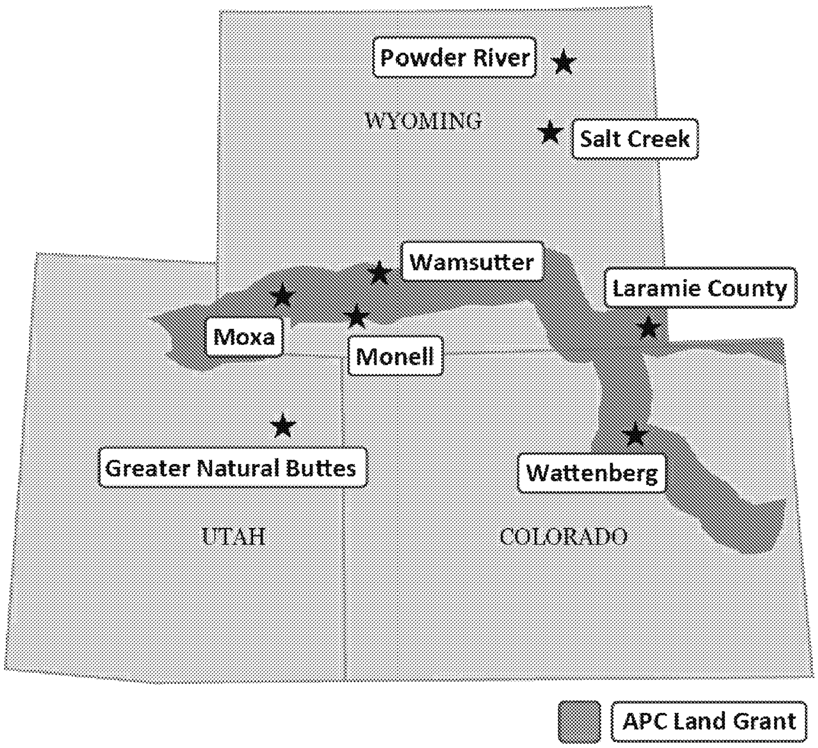
United States

Overview Anadarko's U.S. operations include oil and natural-gas exploration and production onshore in the Lower 48 states, the deepwater Gulf of Mexico, and onshore Alaska. The Company's U.S. operations accounted for 89% of total sales volumes during 2014 and 92% of total proved reserves at year-end 2014.

Rocky Mountains Region Anadarko's Rocky Mountains Region (Rockies) properties include oil and natural-gas plays located in Colorado, Utah, and Wyoming where the Company operates approximately 14,500 wells and owns an interest in approximately 8,000 nonoperated wells. Anadarko operates fractured-carbonate/shale reservoirs, tight-gas assets, coalbed-methane (CBM) natural-gas assets, and enhanced oil recovery (EOR) projects within the region. The Company also has fee ownership of mineral rights under approximately eight million acres that pass through Colorado, Wyoming, and into Utah (known as the Land Grant). Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production on Land Grant acreage, offers drilling opportunities for the Company without expiration, and allows the Company to capture royalty revenue from third-party activity on Land Grant acreage. The Company also believes its liquids-rich reservoirs, strong well performance, low development and operating costs, and large expandable midstream infrastructure each provide tangible benefits to the Company.

Activities in the Rockies primarily focus on expanding existing fields to increase production and adding proved reserves through horizontal drilling, infill drilling, and down-spacing operations. The Company focused its 2014 capital investments in areas that offer high liquids yields (liquids-rich areas), which resulted in significant oil production growth. In 2014, total-year Rockies sales volumes increased 10% over 2013, with a 45% or 49 thousand barrels of oil equivalent per day (MBOE/d) increase in liquids volumes. The Company drilled 569 wells and completed 487 wells in the Rockies during 2014. The Company plans to continue its drilling program in 2015, focusing on the Wattenberg field.



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Wattenberg Anadarko operates approximately 5,800 vertical wells and 750 horizontal wells in the Wattenberg field. The field contains the Niobrara and Codell formations, which are naturally fractured formations that hold liquids and natural gas. During 2014, the Company's drilling program focused entirely on horizontal development, drilling 369 horizontal wells. Sales volumes in the Wattenberg field increased 55% compared to 2013, with year-over-year increases of 69% in oil volumes and 79% in total liquids volumes. Horizontal drilling results in the Wattenberg field continue to be strong, with economics that are enhanced by the Land Grant mineral interest, a consolidated core acreage position, and recent enhancements in infrastructure and takeaway capacity.

Major facility and takeaway expansions occurred in 2014. The Lancaster cryogenic plant and Front Range Pipeline (FRP) were commissioned in 2014. The Lancaster cryogenic plant resulted in a field-wide increase in NGLs recoveries and the FRP resulted in access to the premium Mt. Belvieu NGLs market. Gas processing capacity is expected to increase in mid-2015 with the addition of Lancaster II, which is a second 300 million cubic feet per day (MMcf/d) cryogenic processing facility currently under construction. The White Cliffs pipeline expansion was completed in the third quarter of 2014, providing additional oil transportation capacity for the region. Management believes that Anadarko is well-positioned with its oil and NGLs export capacity, which includes transport by pipeline, rail, and truck.

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is one of the Company's major tight-gas assets. The Company utilizes both refrigeration and cryogenic processing facilities in this area to extract NGLs from the natural-gas stream.

The Company operates approximately 2,800 wells in the Greater Natural Buttes area and drilled 133 wells in 2014. The Company operated the field at a reduced activity level for the majority of 2014 due to capital allocation to higher-margin projects.

Powder River Deep The Company drilled 10 horizontal wells in the Powder River basin during 2014 as part of a multi-objective horizontal exploration program targeting oil opportunities. The Company has seen encouraging results in the Niobrara and Turner formations. Anadarko controls over 350,000 acres of deep mineral rights within the Powder River basin.

Coalbed Methane Properties Anadarko operates approximately 2,300 CBM wells and owns an interest in approximately 2,500 nonoperated CBM wells in the Rockies, primarily located in the Powder River basin in Wyoming and the Helper and Clawson fields in Utah. Anadarko controls over 640,000 acres of shallow rights within the Powder River basin. CBM is natural gas that is generated and stored within coal seams. To produce CBM, water is extracted from the coal seam, resulting in reduced pressure and the release of natural gas, which flows to the wellhead. The Company operated the field at a reduced activity level in 2014 due to capital allocation to higher-margin projects.

Salt Creek and Monell During 2014, the Company continued the development of its Rockies EOR assets in the Salt Creek and Monell fields in Wyoming. The Company's EOR operations use carbon dioxide (CO_2) to stimulate oil production from mature reservoirs after primary and water-flood recovery methods have been completed. Significant gains in production were achieved in this area due to the Company's ongoing development programs, with oil production rising 10% in 2014. In 2015, the Company plans to continue the management of these fields to enhance CO_2 flooding operations.

In 2012, the Company entered into a carried-interest arrangement where a third party agreed to fund $400 million of development costs in exchange for a 23% interest in the Company's EOR development in the Salt Creek field in Wyoming. The funding commitment was completed in 2014.

Laramie County, Wyoming Anadarko holds ownership in more than 100,000 mineral-interest acres in this emerging liquids-rich play, targeting the Niobrara and Codell formations in the northern DJ Basin. In 2014, the Company participated in more than 70 nonoperated wells testing the Niobrara and Codell formations. Early results from wells drilled in 2014 are encouraging, as results from the 19 nonoperated wells that are currently producing remain strong with initial 30-day net production averaging approximately 1,000 barrels of oil equivalent per day (BOE/d).

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Greater Green River Basin Anadarko operates over 1,400 wells in the Wamsutter and Moxa fields, which are primarily dry-gas assets. The Company also carries a nonoperated position in 2,600 wells between the two fields. Much of this producing area is in the Land Grant, which improves the economics of projects in the area.

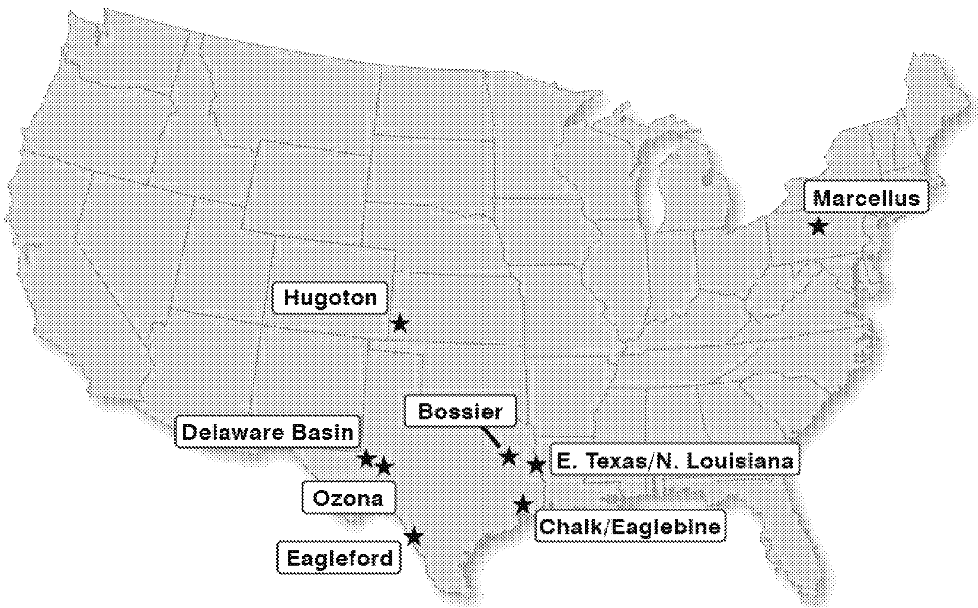
In late 2013, Anadarko acquired additional working interests and became the operator in the Moxa field, increasing the Company's net production by approximately 6,500 BOE/d. In 2014, additional value was realized through reduction in the decline rates and decreasing operating costs.

In January 2014, Anadarko sold its interest in the Pinedale/Jonah assets in Wyoming for $581 million.

Southern and Appalachia Region Anadarko's Southern and Appalachia Region properties are primarily located in Texas, Pennsylvania, Louisiana, and Kansas. The region includes the Eagleford shale in South Texas, the Delaware basin in West Texas, the Marcellus shale in north-central Pennsylvania, and the Haynesville shale in East Texas and Louisiana. Operations in these areas are focused on finding and developing both natural gas and liquids from shales, tight sands, and fractured-reservoir plays.

During 2014, the Company continued to focus on liquids-rich opportunities across the region by expanding drilling activity in the emerging Wolfcamp shale play in the Delaware basin and other shale plays, while continuing its existing liquids-rich projects in the Eagleford shale, Delaware basin, and East Texas/North Louisiana plays. The Company has reduced costs and benefited from improved cycle-time efficiencies in both drilling and completion operations across all operating areas in the region.

In 2014, total-year sales volumes in the Southern and Appalachia Region increased 16% over 2013, with a 33% increase in liquids volumes. The Company drilled 589 operated horizontal wells and brought 730 wells online in 2014. In 2015, the Company expects to continue its horizontal drilling program, focusing on the Texas assets.



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Eagleford The Eagleford shale development in South Texas consists of approximately 357,000 gross acres and over 1,100 producing wells. The Company drilled 393 wells, completed 388 wells, and brought 385 wells online generating 47% sales volume growth year over year. Anadarko entered 2014 with 10 drilling rigs and reduced the rig count to eight by the end of 2014 due to outstanding drilling performance. To facilitate additional completion activities, water infrastructure was expanded in 2014, increasing capacity by 75 thousand barrels per day (MBbls/d). The Company continues to test concepts for additional recovery across its acreage position and completed successful tests on two upper-Eagleford shale wells.

Delaware Basin Anadarko holds an interest in over 600,000 gross acres in the Delaware basin. Anadarko's 2014 drilling activity primarily targeted the liquids-rich Bone Spring formation, the Avalon shale, and the developing Wolfcamp shale play. In 2014, Anadarko drilled 97 operated wells and participated in 43 nonoperated wells. Significant infrastructure was added, which increased NGLs sales volumes by 82% over 2013. In addition, in November 2014, Western Gas Partners, LP (WES), a consolidated subsidiary of the Company, acquired Nuevo Midstream, LLC (Nuevo), which has gathering and processing assets located in the Delaware basin. The Company had one operated rig drilling in the Bone Spring formation, one operated rig drilling in the Avalon shale, and eight operated rigs drilling in the Wolfcamp shale at year-end 2014.

The successful Wolfcamp shale delineation program continues to deliver encouraging results across the majority of Anadarko's acreage position. Anadarko is testing multiple zones within the Wolfcamp shale and several development concepts including multi-well pads, extended laterals, and horizontal well spacing for increased efficiency. The Company has identified thousands of potential drilling locations in the Wolfcamp formations that are expected to provide substantial opportunity for Anadarko's continued activity in the basin.

Eaglebine Anadarko holds 156,000 gross acres in the Eaglebine shale in Southeast Texas, most of which is held by existing Austin Chalk production. In 2014, Anadarko continued to delineate and develop this acreage with a one-rig drilling program. In September 2014, the Company entered into a carried-interest arrangement requiring a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development. Anadarko will remain the operator with an average post-transaction working interest of approximately 51%. This transaction allows the Company to develop this oil opportunity while further enhancing Anadarko's capital efficiency and flexibility. At December 31, 2014, $22 million of the total $442 million obligation had been funded.

East Texas/North Louisiana Anadarko holds 293,000 gross acres in East Texas/North Louisiana. Anadarko increased its capital program in the East Texas Carthage area in 2014, targeting a liquids-rich area in the Haynesville shale. In 2014, Anadarko operated six rigs and drilled 52 wells in the Haynesville and Cotton Valley formations. The Company increased sales volumes from the area by 10% year over year.

Marcellus The Company holds 654,000 gross acres in the Marcellus shale of the Appalachian basin. During the year, 24 operated horizontal wells were drilled using one rig. Anadarko also participated in drilling an additional 78 nonoperated horizontal wells in 2014. The Company's production in Marcellus continued to improve with sales volumes increasing 12% over 2013.

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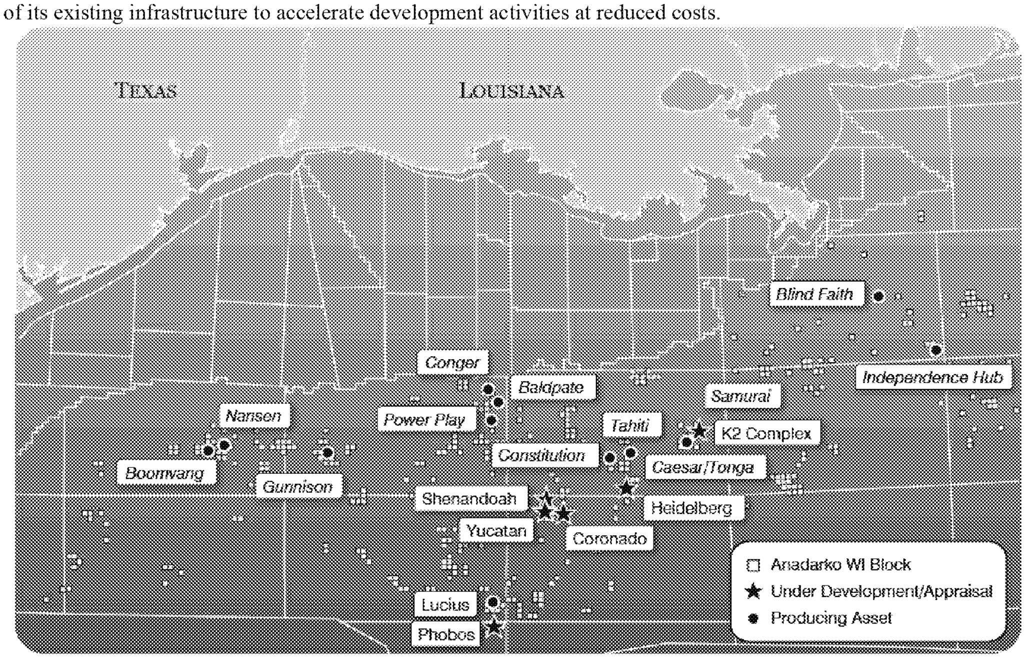
Gulf of Mexico In the Gulf of Mexico, Anadarko owns an average 61% working interest in 394 blocks. The Company operates seven active floating platforms and holds interests in 23 producing fields. During 2014, the Company advanced development of the Lucius and Heidelberg projects and continued an active deepwater development and appraisal program in the Gulf of Mexico as it continues to take advantage of its existing infrastructure to accelerate development activities at reduced costs.



The following includes the significant development, exploration, and appraisal activity in the Gulf of Mexico during 2014.

Development

Lucius The Company realized first production at the Anadarko-operated Lucius Spar in January 2015, bringing on three wells initially and ramping up production with an additional three wells expected to come online during the first quarter of 2015. The successful Lucius project was developed with production startup only three years from sanction and five years from discovery. The 80-MBbls/d spar resides in Keathley Canyon Block 875 with a water depth of 7,100 feet.

A carried-interest arrangement with a third party, entered into in 2012, provided funding for the substantial majority of Anadarko's development capital commitment through first production. Following the carried-interest arrangement and 2014 equity re-determination, the Company holds a 23.8% working interest in Lucius.

Heidelberg The Company continues to advance the Anadarko-operated Heidelberg development project, which was sanctioned during the second quarter of 2013. The construction of the 80-MBbls/d spar is progressing on schedule with anticipated start-up in 2016. At December 31, 2014, fabrication of the main topsides module was more than 70% complete and ahead of schedule.

In 2013, the Company entered into a carried-interest arrangement requiring a third party to fund $860 million of capital costs in exchange for a 12.75% working interest in the project. The carry obligation is expected to cover the substantial majority of the Company's expected future capital costs through first production. At December 31, 2014, $386 million of the $860 million obligation had been funded. Anadarko holds a 31.5% working interest in Heidelberg. Development drilling commenced in late 2014 on two development wells.

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Caesar/Tonga At Caesar/Tonga (33.75% working interest), the Company successfully completed a fourth development well (GC 727#2) in the first quarter of 2014, and the well is producing 10 MBbls/d of oil. Anadarko is currently completing a fifth development well (GC 683#2), which is expected to come online during the first quarter of 2015.

K2 At K2 (41.8% working interest), the GC 562 #5 infill well found 210 feet of oil pay in the Miocene, and the well is being sidetracked for a subsequent completion. The well is expected to come online in the second half of 2015.

Constitution At Constitution (100% working interest), the Company executed a successful platform drilling program in 2014, where the A1 well was sidetracked, completed, and brought online producing 3 MBbls/d of oil.

Vito In 2014, Anadarko sold its 18.67% working interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks, for $500 million.

Exploration

Three exploration wells were drilled in the Gulf of Mexico during 2014. The Deep Nansen exploration well (35% working interest) targeted Lower Tertiary-aged sediments in a large, four-way structure beneath Anadarko's Nansen field and found non-commercial quantities of hydrocarbons and the well was plugged and abandoned. The evidence of a working petroleum system is being incorporated into potential future activity on the surrounding leasehold. The Bimini exploration well (50% working interest) was drilled in Garden Banks close to existing infrastructure at the Anadarko-operated Power Play field and near the Conger field and Baldpate Platform. The well tested a subsalt Miocene prospect and was plugged and abandoned. The K2 development well was drilled deeper to test the Wilcox potential beneath the existing field in Green Canyon and did not find commercial quantities of hydrocarbons in the Wilcox objective. The K2 well will be sidetracked and completed in a field pay interval. Also, the Yeti exploration well (37.5% nonoperated working interest) was spud prior to year end. The well will test a Miocene sub-salt three-way closure in Walker Ridge.

Appraisal

Shenandoah Basin The Company spud the Shenandoah-3 well, its second appraisal well at the Shenandoah discovery, in the second quarter of 2014. The well finished drilling at the end of 2014 and found approximately 50% (1,470 feet) more of the same reservoir sands 1,500 feet down-dip and 2.3 miles east of the Shenandoah-2 well, which encountered over 1,000 feet of net oil pay in excellent quality Lower Tertiary-aged sands. The Shenandoah-3 well confirmed the sand depositional environment, lateral sand continuity, excellent reservoir qualities, and down-dip thickening. The well also enabled the projection of oil-water contacts based on pressure data and reduced the uncertainty of the resource range. Planning is underway for the next appraisal well, which the Company expects to spud in the second quarter of 2015.

An appraisal well at the Coronado discovery (35% working interest) reached total depth during the second quarter of 2014 and did not find the Lower Miocene objective and was plugged and abandoned.

During the third quarter of 2014, the first appraisal well of the Yucatan discovery (25% working interest) was drilled down-dip of the original discovery, and found approximately 57 gross feet of pay in Lower Tertiary oil-bearing sands. The Yucatan discovery is located approximately three miles south of the Shenandoah discovery.

Alaska Anadarko's nonoperated oil production and development activity in Alaska is concentrated on the North Slope. Infrastructure construction began in 2013 on the Alpine West satellite development, a 15-to-20-well extension of the Alpine field. Drilling at Alpine West is scheduled to commence in mid-2015 with production anticipated to come online in late 2015 or early 2016.

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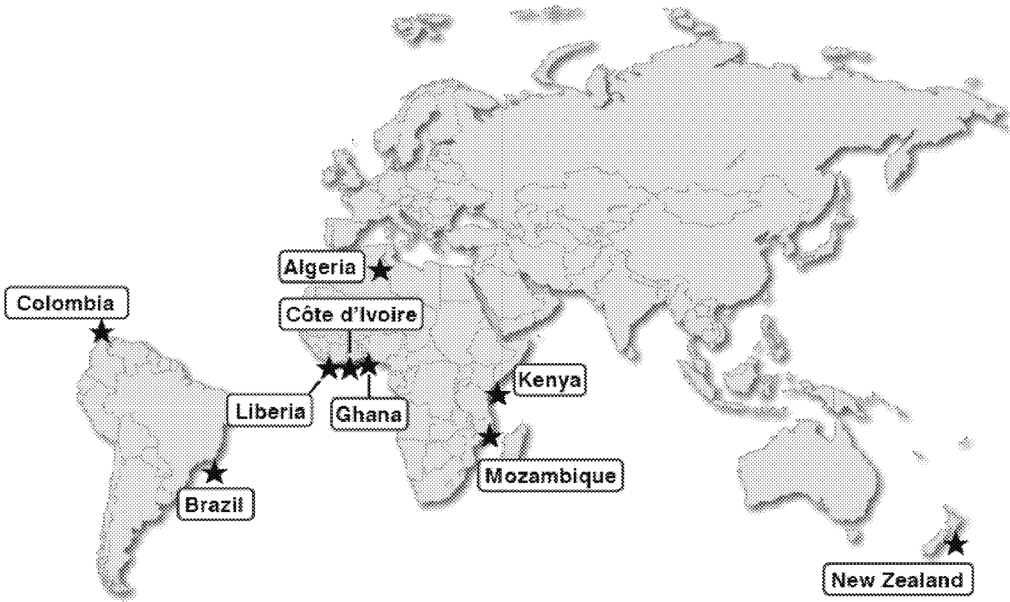
International

Overview Anadarko's international operations include oil, natural-gas, and NGLs production and development in Mozambique, Algeria, and Ghana. The Company also has exploration acreage in Brazil, Colombia, Côte d'Ivoire, Ghana, Kenya, Liberia, Mozambique, New Zealand, and other countries. International locations accounted for 11% of Anadarko's total sales volumes and 21% of sales revenues during 2014, and 8% of total proved reserves at year-end 2014. In 2015, the Company expects to focus its exploration and appraisal activity in East Africa, Côte d'Ivoire, and Colombia.



Mozambique Anadarko operates two blocks (one onshore and one offshore) totaling approximately 5.3 million gross acres at December 31, 2014. From a construction, finance, and marketing perspective, the Company is positioned to commence project execution and deliver first cargoes in the expected 2019 timeframe; however, the pace of this project is dependent upon securing necessary approvals from the government of Mozambique.

Development In February 2014, the Company sold a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion. Anadarko remains the operator of Offshore Area 1 with a working interest of 26.5%.

During 2014, the Company obtained reserves certification from a third party indicating sufficient volumes to support an initial LNG development. The Environmental Impact Assessment was approved by the government of Mozambique. The Company completed front-end engineering and design (FEED) for the onshore liquefaction facilities and the offshore gathering infrastructure and is in the process of selecting the contractor groups for construction. Anadarko and its partners reached non-binding Heads of Agreements for long-term LNG sales to buyers in Asian markets covering in excess of eight million metric tonnes per annum. In December 2014, the Mozambique government published a Decree Law that is sufficient to continue progressing project finance, marketing, and construction and operation of an LNG project. This legislation marks a critical step toward establishing a project-wide legal and contractual framework that delivers a level of fiscal stability enabling continued equity investments by the Company and potential access to significant limited-recourse project finance capital.

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Exploration In the Offshore Area 1, the Tubarão Tigre-1 exploration well was drilled approximately 37 miles south of the Orca-1 discovery well and encountered more than 92 feet of net gas pay in Paleocene sands. The Ouriço do Mar exploration well was drilled 22.5 miles south of the Orca-1 discovery well and tested the potential down-dip extent of the Paleocene reservoirs found in the Orca and Tubarão Tigre discoveries. The well was plugged and abandoned during the third quarter of 2014. Appraisal of the Orca discovery continued with the drilling of three appraisal wells. During the first quarter of 2014, the Orca-2 well encountered 151 feet of Paleocene reservoir sand with the top 26 feet being charged, establishing the gas/water contact for the discovery. The rig moved to the Orca-3 location and encountered 102 net feet of natural-gas pay in the Paleocene. The Orca-4 well reached total depth during the fourth quarter of 2014 encountering natural-gas pay in two reservoirs. At the end of 2014, the rig was located at Tubarão Tigre-2 drilling the first appraisal well associated with the Tubarão Tigre discovery. Data from these wells will be used to further delineate the size of the resource and determine future appraisal activity for the Orca and Tubarão Tigre discoveries.

In the Onshore Rovuma (35.7% working interest), the Anadarko-operated Tembo-1 well completed drilling at the end of the fourth quarter in 2014. The well encountered gas and condensate in one of the Cretaceous reservoirs and post-drill evaluations are underway to determine if additional exploration is warranted within the prospect area. A rig has been mobilized to the second well in the program, Kifaru, which will test Miocene, Oligocene, and Paleocene gas targets near the future LNG facility site.

Algeria Anadarko is engaged in production and development operations in Algeria's Sahara Desert in Blocks 404 and 208, which are governed by a Production Sharing Agreement between Anadarko, two other parties, and Sonatrach, the national oil and gas company of Algeria. The Company is responsible for 24.5% of the development and production costs for these blocks. The Company produces oil through the Hassi Berkine South and Ourhoud central processing facilities (CPF) in Block 404 and oil, condensate, and NGLs through the El Merk CPF in Block 208. Gross production through these facilities averaged more than 383 MBbls/d in 2014, and a quarterly net production record of approximately 75 MBOE/d was achieved as all of the fields at the El Merk CPF were increased to full oil production rates. The Company drilled nine development wells in 2014.

Ghana Anadarko's production and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block.

The Jubilee field (27% nonoperated unit interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block, averaged gross production of 102 MBbls/d of oil in 2014. In the fourth quarter of 2014, a pipeline tie-in was completed and natural-gas exports commenced from the Jubilee field to an onshore gas processing plant. The natural-gas exports are being delivered to satisfy a commitment established in conjunction with the Jubilee development plan and are expected to allow increases in future oil production rates. The Company and its partners are evaluating options to further expand the oil throughput capacity of the floating production, storage, and offloading vessel (FPSO) and expect to submit a full-field development plan for the Jubilee field to the government of Ghana in 2015.

The Jubilee J-24 development well was drilled deeper to evaluate the Mahogany sands below the Jubilee reservoirs. Additional appraisal work was completed in 2014 in the Mahogany and Akasa fields and the data is under evaluation.

In 2013, development commenced on the Tweneboa/Enyenra/Ntomme (TEN) project (19% nonoperated working interest). The project will use an 80-MBbls/d-capacity FPSO for production from subsea wells. Significant progress was made during 2014, including engineering design completion, the successful dry-docking of the FPSO, and drilling of the first nine wells. The project was approximately 50% complete at year-end 2014 and remains on budget and on schedule for first production in 2016.

China In August 2014, the Company sold its Chinese subsidiary for $1.075 billion.

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Brazil Anadarko holds exploration interests in approximately 300,000 gross acres in two offshore blocks located in the Campos basin. At the Wahoo discovery, the Company is evaluating commercialization options by performing pre-FEED and FEED studies.

Colombia During 2014, Anadarko was the high bidder on the COL1, COL 6, and COL 7 blocks. At December 31, 2014, Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on nine blocks, totaling 16 million acres. The COL 1, COL 2, COL 6, and COL 7 blocks are operated at 100% working interest and the remaining blocks are operated at a 50% working interest.

Two initial prospects have been selected for the 2015 exploration drilling program. The Calasu prospect is a large four-way structure on the north end of the Fuerte Norte block. It has multiple targets and success would reduce the risk of several adjacent structures on the block. The Kronos prospect is located in the Fuerte Sur block and will test a large structure associated with the frontal area of a large thrust complex. As with Calasu, success would reduce the risk of multiple prospects. The two-well program commenced in early 2015.

Côte d'Ivoire Anadarko owns an operated working interest in five offshore blocks totaling approximately 1.3 million acres, including CI-515 and CI-516 each with a 45% working interest, CI-103 with a 65% working interest, and CI-528 and CI-529 each with a 90% working interest.

The Company continued appraisal of the Cretaceous Paon discovery in Block CI-103, where the discovery well encountered 100 feet of net pay. The Paon-3AR was drilled 3.7 miles down-dip to the discovery well and encountered more than 94 feet of pay. The well established an oil/water contact and appears to be in communication with the Paon-1X discovery. As a result of the success, the drilling of the Paon-4A was accelerated. The well, located six miles east of the Paon-3AR, penetrated over 37 feet of pay in the target section and defined the eastern extent of the reservoir. During 2014, Anadarko became operator of the block and farmed down a portion of the working interest for a carry on the appraisal activities. Based on the successful drilling program to date, the partnership and the government are currently discussing additional appraisal drilling activity for 2015, which would include a drillstem test.

The Morue prospect in Block CI-516 was drilled and encountered a small accumulation of oil in the well-developed sands in the targeted interval, and was plugged and abandoned as non-commercial.

The Saumon prospect was drilled in Block CI-515 during 2014. The well reached total depth and did not find hydrocarbons. The well was plugged and abandoned.

Kenya Anadarko owns and operates a 45% working interest in five offshore deepwater blocks, encompassing approximately 5.6 million gross acres. An exploration well is currently planned to test a large four-way structure at the Mlima prospect in Block L-11B during 2015.

Liberia Two exploration wells were drilled in Block LB-10 (50% working interest) during 2014. The Anadarko-operated Iroko and Timbo wells both encountered non-commercial quantities of oil in their primary targets and were plugged and abandoned. Post-well evaluation is underway to determine the remaining prospectivity of the block. Anadarko completed a farm down prior to drilling, which covered a majority of the drilling costs for these two wells.

New Zealand Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on four blocks totaling 42 million acres, of which 6.1 million acres are owned under exploration licenses. Anadarko operates a 45% working interest in the Canterbury basin block and a 100% working interest in two Pegasus basin blocks. In the 36 million acre New Caledonia basin block, Anadarko controls a 25% nonoperated working interest. The Caravel prospect reached its total-depth objective in the Canterbury basin block and was plugged and abandoned, having encountered natural gas shows and high-quality reservoir in the primary objective. A seismic acquisition is planned during 2015 on the block.

Other Anadarko also has exploration projects in other overseas, new-venture areas including Tunisia and South Africa.

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Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in billions of cubic feet (Bcf), at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil, condensate, and NGLs. Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes. Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year.

Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria and Ghana, which by country and in total represents less than 15% of the Company's total proved reserves. The Company sold its Chinese subsidiary during 2014.

Summary of Proved Reserves

	Natural Gas (Bcf)	Oil and Condensate (MMBbls)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2014				
Proved				
Developed				
United States	**6,635**	**352**	**304**	**1,762**
International	**27**	**190**	**13**	**207**
Undeveloped				
United States	**2,033**	**352**	**162**	**853**
International	**4**	**35**	**-**	**36**
Total proved	**8,699**	**929**	**479**	**2,858**
December 31, 2013				
Proved				
Developed				
United States	7,120	347	268	1,801
International	-	202	-	202
Undeveloped				
United States	2,085	245	127	720
International	-	57	12	69
Total proved	9,205	851	407	2,792
December 31, 2012				
Proved				
Developed				
United States	6,445	318	283	1,675
International	-	208	-	208
Undeveloped				
United States	1,884	193	110	617
International	-	48	12	60
Total proved	8,329	767	405	2,560

The Company's year-end 2014 proved reserves product mix was comparable to the last two years with 51% natural gas, 33% oil and condensate, and 16% NGLs.

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Anadarko is focused on growth and profitability, and reserves replacement is a key to growth. Future profitability partially depends on commodity prices and the cost of finding and developing oil and gas reserves. Reserves growth can be achieved through successful exploration and development drilling, improved recovery, or acquisition of producing properties.

MMBOE	**2014**	2013	2012
Proved Reserves			
January 1	**2,792**	2,560	2,539
Reserves additions and revisions			
Discoveries and extensions	**63**	145	82
Infill-drilling additions (1)	**577**	410	383
Drilling-related reserves additions and revisions	**640**	555	465
Other non-price-related revisions (1)	**(137)**	(40)	(31)
Net organic reserves additions	**503**	515	434
Acquisition of proved reserves in place	**-**	36	4
Price-related revisions (1)	**(1)**	(23)	(68)
Total reserves additions and revisions	**502**	528	370
Sales in place	**(124)**	(12)	(81)
Production	**(312)**	(284)	(268)
December 31	**2,858**	2,792	2,560
Proved Developed Reserves			
January 1	**2,003**	1,883	1,811
December 31	**1,969**	2,003	1,883

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information* under Item 8 of this Form 10-K. Reserves bookings related to infill drilling additions are treated as positive revisions. Other non-price-related revisions in 2014 are driven by a reduction of 116 MMBOE in the Wattenberg area primarily associated with the optimization of horizontal drilling locations and the discontinuation of vertical well workover plans.

The Company's estimates of proved developed reserves, proved undeveloped reserves (PUDs), and total proved reserves at December 31, 2014, 2013, and 2012, and changes in proved reserves during the last three years are presented in the *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K. Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2014. Annually, Anadarko reports gross proved reserves for U.S.-operated properties to the U.S. Department of Energy. These reported reserves are derived from the same database used to estimate and report proved reserves in this Form 10-K.

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Changes in PUDs Changes to PUDs occurring during 2014 are summarized in the table below. Revisions of prior estimates reflect Anadarko's ongoing evaluation of its asset portfolio and include updates to prior PUDs, the addition of new PUDs associated with current development plans, the transfer of PUDs to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at January 1, 2014	**789**
Revisions of prior estimates	**333**
Extensions, discoveries, and other additions	**32**
Conversion to developed	**(210)**
Sales	**(55)**
PUDs at December 31, 2014	**889**

Revisions In 2014, PUD revisions of 333 MMBOE were primarily related to successful infill drilling in large onshore areas such as Wattenberg in the Rockies and the Eagleford shale in the Southern and Appalachia Region, partially offset by decreases primarily due to development plan updates.

Extensions, Discoveries, and Other Additions During 2014, Anadarko added 32 MMBOE of PUDs through extensions, discoveries, and other additions, primarily as a result of successful drilling in the Marcellus and Wolfcamp shale plays in the Southern and Appalachia Region.

Conversions In 2014, the Company converted 210 MMBOE, or 27% of total year-end 2013 PUDs, to developed status. Approximately 73% of PUD conversions occurred in U.S. onshore assets, 16% in international assets, and the remaining 11% in Gulf of Mexico assets.

Development activity in the U.S. onshore assets resulted in the conversion of 80 MMBOE in the Southern and Appalachia Region and 72 MMBOE in the Rockies. Ongoing development activity in the Company's Algerian assets resulted in the conversion of 34 MMBOE in 2014. The remaining PUD conversions were associated with development projects in various Gulf of Mexico fields.

Anadarko spent $1.6 billion to develop PUDs in 2014, of which approximately 74% related to U.S. onshore assets, 13% related to Gulf of Mexico assets, and 13% related to international assets.

In 2013, the Company converted 183 MMBOE, or 27% of the total year-end 2012 PUDs, to developed status. Approximately 85% of PUD conversions occurred in U.S. onshore assets, 11% in international assets, and the remaining 4% in Gulf of Mexico assets. Anadarko spent $1.0 billion on PUD development in 2013, of which approximately 70% related to domestic development programs in the Rockies and the Southern and Appalachia Regions, 25% related to development of international projects, and the remaining 5% related to Alaska and Gulf of Mexico development projects.

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Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, U.S. onshore PUDs are converted to developed reserves within five years of the initial proved reserves booking, but projects such as EOR, arctic development, deepwater development, and international programs may take longer. All of the Company's U.S. onshore PUDs at December 31, 2014, were scheduled to be developed within five years, with the exception of the Salt Creek EOR project, the annual development of which is limited by CO_2 supply.

At December 31, 2014, the Company had 39 MMBOE of pre-2010 PUDs that remained undeveloped. Approximately 51% of these PUDs are associated with Gulf of Mexico opportunities where longer development times are a result of delays associated with operating in a deepwater environment, including delays associated with the development and adoption of enhanced safety procedures and other regulatory changes following the Deepwater Horizon event.

Another 33% of the Company's pre-2010 PUDs are associated with the Salt Creek EOR single-development project located in the Rockies. Since 2003, Anadarko has invested an average of $90 million per year to develop the Salt Creek EOR project and will continue similar spending levels in the future.

The remaining pre-2010 PUDs are associated with the El Merk development project and are being developed according to an Algerian government-approved plan. Anadarko and its partners achieved initial oil production in 2013 and the El Merk facility reached maximum allowable oil production rates in 2014 when all the fields were brought online and the facility became fully operational.

Technologies Used in Proved Reserves Estimation The Company's 2014 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data used also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs), as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserves estimates. All QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserves estimates. The Director-Reserves Administration and the Corporate Reserves Manager manage the CRG and report to the VP-Corporate Planning. The VP-Corporate Planning reports to the Company's Executive Vice President, Finance and Chief Financial Officer, who in turn reports to the Chairman, President, and Chief Executive Officer. The Governance and Risk Committee of the Company's Board of Directors meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss the results of procedures and methods reviews as discussed below, as well as other matters and policies related to reserves.

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The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 28 years of experience in the oil and gas industry, including over 14 years as either a reserves estimator or manager. His further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. The principal engineer is a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers, where he has been a member for over 28 years. In addition, he is an active participant in industry reserves seminars and professional industry groups.

Third-Party Procedures and Methods Reviews M&L reviewed the procedures and methods used by Anadarko's staff in preparing the Company's estimates of proved reserves and future net cash flows at December 31, 2014. The purpose of the review was to determine if the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods reviews by M&L were limited reviews of Anadarko's procedures and methods and do not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The reviews covered 16 fields that included major assets in the United States and Africa, and encompassed approximately 88% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2014. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures, and relevant economic criteria.

Management's intent in retaining M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

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Sales Volumes, Prices, and Production Costs

The Company's sales volumes were 308 MMBOE for 2014, 285 MMBOE for 2013, and 268 MMBOE for 2012. Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related general and administrative costs. Additional information on volumes, prices, and production costs is contained in *Financial Results* under Item 7 of this Form 10-K. Additional detail regarding production costs is contained in the *Supplemental Information* under Item 8 of this Form 10-K. Information on major customers is contained in *Note 20-Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. The following provides the Company's annual sales volumes, average sales prices, and average production costs per BOE for each of the last three years:

	Sales Volumes				Average Sales Prices [1]			
	Natural Gas (Bcf)	Oil and Condensate (MMBbls)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Natural Gas (Per Mcf)	Oil and Condensate (Per Bbl)	NGLs (Per Bbl)	Average Production Costs [2] (Per BOE)
2014								
United States								
Greater Natural Buttes	**154**	**1**	**4**	**31**	**$ 3.93**	**$ 81.74**	**$ 39.16**	**$ 10.30**
Wattenberg	**125**	**27**	**13**	**62**	**4.19**	**87.76**	**36.46**	**8.00**
Other United States	**666**	**46**	**26**	**182**	**4.08**	**88.29**	**34.29**	**9.28**
Total United States	**945**	**74**	**43**	**275**	**4.07**	**87.99**	**35.48**	**9.11**
International	**-**	**32**	**1**	**33**	**-**	**99.79**	**56.16**	**8.22**
Total	**945**	**106**	**44**	**308**	**4.07**	**91.58**	**36.01**	**9.01**
2013								
United States								
Greater Natural Buttes	168	1	4	33	$ 3.12	$ 87.46	$ 41.79	$ 9.59
Wattenberg	102	16	6	40	3.75	94.27	41.75	8.55
Other United States	698	41	23	179	3.56	98.38	36.14	8.72
Total United States	968	58	33	252	3.50	97.02	37.97	8.81
International	-	33	-	33	-	109.15	-	9.96
Total	968	91	33	285	3.50	101.41	37.97	8.94
2012								
United States								
Greater Natural Buttes	163	1	5	33	$ 2.26	$ 81.34	$ 40.43	$ 8.75
Wattenberg	95	12	5	33	3.00	92.16	40.72	8.05
Other United States	655	42	20	171	2.73	99.36	40.37	8.76
Total United States	913	55	30	237	2.68	97.46	40.44	8.66
International	-	31	-	31	-	111.11	-	10.89
Total	913	86	30	268	2.68	102.35	40.44	8.92

Mcf-thousand cubic feet
Bbl-barrel
[1] Excludes the impact of commodity derivatives.
[2] Excludes ad valorem and severance taxes.

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Delivery Commitments

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2014, Anadarko was contractually committed to deliver approximately 874 Bcf of natural gas to various customers in the United States through 2031. These contracts have various expiration dates with approximately 45% of the Company's current commitment to be delivered in 2015, and 70% by 2019. At December 31, 2014, Anadarko also was contractually committed to deliver approximately 9 MMBbls of oil to ports in Algeria and Ghana through 2015. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2014:

	Developed Lease		Undeveloped Lease		Fee Mineral		Total	
thousands of acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States								
Onshore	5,069	3,314	5,203	2,140	10,313	8,472	20,585	13,926
Offshore	293	139	2,079	1,401	-	-	2,372	1,540
Total United States	5,362	3,453	7,282	3,541	10,313	8,472	22,957	15,466
International	499	113	56,725	39,328	-	-	57,224	39,441
Total	5,861	3,566	64,007	42,869	10,313	8,472	80,181	54,907

At December 31, 2014, the Company had approximately 26 million net undeveloped lease acres scheduled to expire by December 31, 2015, if the Company does not establish production or take any other action to extend the terms. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions and does not expect a significant portion of the Company's net acreage position to expire before such actions occur.

Drilling Program

The Company's 2014 drilling program focused on proven and emerging oil and natural-gas basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2014 consisted of 88 gross completed wells, which included 71 U.S. onshore wells, five Gulf of Mexico wells, and 12 international wells. Development activity in 2014 consisted of 1,268 gross completed wells, which included 1,264 U.S. onshore wells and four Gulf of Mexico wells.

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Drilling Statistics

The following shows the number of oil and gas wells that completed drilling in each of the last three years:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2014							
United States	**35.6**	**1.6**	**37.2**	**811.4**	**6.0**	**817.4**	**854.6**
International	**0.9**	**4.5**	**5.4**	**-**	**-**	**-**	**5.4**
Total	**36.5**	**6.1**	**42.6**	**811.4**	**6.0**	**817.4**	**860.0**
2013							
United States	62.9	1.4	64.3	879.3	3.3	882.6	946.9
International	0.2	3.5	3.7	5.4	-	5.4	9.1
Total	63.1	4.9	68.0	884.7	3.3	888.0	956.0
2012							
United States	79.5	1.0	80.5	923.7	11.3	935.0	1,015.5
International	0.5	3.0	3.5	2.1	-	2.1	5.6
Total	80.0	4.0	84.0	925.8	11.3	937.1	1,021.1

The following shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2014:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion [(1)]	
	Exploration	Development	Exploration	Development
United States				
Gross	7	186	60	861
Net	3.8	118.6	28.2	557.9
International				
Gross	2	-	57	19
Net	0.9	-	17.8	4.2
Total				
Gross	9	186	117	880
Net	4.7	118.6	46.0	562.1

(1) Wells suspended or waiting on completion include exploration and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

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Productive Wells

At December 31, 2014, the Company's ownership interest in productive wells was as follows:

	Oil Wells (1)	Gas Wells (1)
United States		
Gross	4,611	28,200
Net	3,157.9	19,271.8
International		
Gross	201	4
Net	36.1	1.0
Total		
Gross	4,812	28,204
Net	3,194.0	19,272.8

(1) Includes wells containing multiple completions as follows:

Gross	245	2,862
Net	216.8	2,401.4

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in and operates midstream (gathering, processing, treating, and transportation) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these facilities, the Company improves its ability to manage costs, controls the timing of bringing on new production, and enhances the value received for gathering, processing, treating, and transporting the Company's production. Anadarko's midstream business also provides services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of contract structures, including fixed-fee, percent-of-proceeds, and keep-whole agreements. Anadarko's midstream activities include WES, which is a publicly traded limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. WES's general partner interest is owned by Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary formed to own substantially all of the partnership interests in WES previously owned by Anadarko. At December 31, 2014, Anadarko's ownership interest in WGP consisted of an 88.3% limited partner interest and the entire non-economic general partner interest. At December 31, 2014, WGP's ownership interest in WES consisted of a 34.9% limited partner interest, the entire 1.8% general partner interest, and all of the WES incentive distribution rights. At December 31, 2014, Anadarko also owned an 8.3% limited partner interest in WES through other subsidiaries.

At the end of 2014, Anadarko had 41 gathering systems and 38 processing and treating plants located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania, and Texas. In 2014, the Company's midstream activity was concentrated in liquids-rich growth areas such as Wattenberg, Greater Natural Buttes, the Delaware basin, the Eagleford shale, and East Texas/North Louisiana plays, as well as in the Marcellus shale dry-gas play. In 2015, the Company plans to continue midstream investments in these core areas.

Wattenberg The Company is constructing a second 300-MMcf/d train at its Lancaster cryogenic processing plant, with completion expected in the second quarter of 2015. The plant will support the increasing production from horizontal drilling in the Niobrara development, helping to relieve processing constraints and improve recoveries of NGLs in the basin. Three new compressor stations are scheduled to come online in the first quarter of 2015 with a total capacity of 120 MMcf/d. In addition, the Company is constructing a Central Oil Stabilization Facility (COSF) with an expected completion date of mid-year 2015. The COSF will stabilize oil in a centralized location and will reduce equipment and installation cost at each well pad. Initial planned throughput for the facility is 125 MBbls/d.

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The Company participates in two long-haul NGL pipeline joint ventures, FRP and Texas Express Pipeline (TEP), which provide access to the Gulf Coast NGLs market. The FRP, which is connected to the Company's Lancaster processing facility, was placed in service in the first quarter of 2014. The FRP extends 435 miles, providing 150 MBbls/d (expandable to 230 MBbls/d) of NGLs takeaway capacity from Weld County, Colorado to Skellytown, Texas. In Skellytown, the FRP connects to other pipelines including the TEP. The TEP extends 593 miles providing 280 MBbls/d (expandable to 400 MBbls/d) of NGLs takeaway capacity to NGLs fractionation and storage facilities in Mont Belvieu, Texas. The Company has ownership interests of 33% in the FRP, 20% in the TEP, and 25% in two NGLs fractionators at Mont Belvieu.

In July 2014, construction of the second pipeline for the White Cliffs Pipeline system was completed and placed in service. This 526-mile dual pipeline system now provides 150 MBbls/d of oil takeaway capacity from Platteville, Colorado to Cushing, Oklahoma. The Company and its joint-venture partners are currently expanding the existing pipeline system to over 200 MBbls/d. The expansion project is scheduled to be completed in mid-2015.

Greater Natural Buttes Chipeta's total processing capacity (cryogenic and refrigeration) is approximately one billion cubic feet per day with cryogenic processing capacity exceeding 600 MMcf/d. Chipeta's third-party pipeline interconnect has added over 100 MMcf/d of natural-gas supply to the plant. Optimization projects, including several pipeline-freeze mitigation projects in the gathering system, have continued to improve the Company's reliability and efficiency.

Wyoming During the second half of 2014, the Company connected five third-party well locations to the Patrick Draw plant. Initial deliveries are expected in the first quarter of 2015. The Company also constructed a 10-mile pipeline in the Barricade unit to gather and deliver the incremental third-party gas to the Company's Patrick Draw plant for processing. Also, gathering connections and expansions in 2014 increased throughput of the Hilight plant by about 40%.

Delaware Basin In 2014, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production in the Delaware basin of West Texas, installing a total of 127 miles of oil and gas gathering lines. Also, significant progress was made towards expanding three central production facilities that will add 30 MBbls/d of capacity upon completion in early 2015. Substantial progress was made on a new CGF with a capacity of 24 MMcf/d, which will be completed in early 2015. The Company entered into a joint-venture agreement with a third party to construct a new 200-MMcf/d cryogenic plant located in Loving County, Texas. The new plant will be operated by the third party.

In November 2014, WES acquired Nuevo, which owns and operates gathering and processing assets located in the Delaware basin. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM). The assets include a 300-MMcf/d cryogenic gas processing plant. WES is preparing to construct an additional 200-MMcf/d cryogenic unit (Train IV) and progress payments have been made towards the construction of another cryogenic unit (Train V), with both expected to come online in 2016.

Eagleford In the Eagleford shale, Anadarko continued the expansion of its infield gathering system with (i) the installation of two new field gas compression facilities, (ii) the addition of incremental compression at Stumberg and Catarina Ranch compressor stations, and the Maverick main central delivery point compression facilities, as well as three other existing field compression facilities, (iii) the completion of approximately 90 miles of gathering pipelines and lateral that connected more than 20 central production facilities, and (iv) enhancements at the main oil-handling facility that increased its reliability and capabilities. The 200-MMcf/d Brasada natural-gas cryogenic processing plant completed its first full year of operations and remains at or near capacity.

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East Texas/North Louisiana In East Texas, the Company continued to expand its midstream infrastructure for Cotton Valley Taylor and Haynesville production in 2014. The high-pressure Haynesville gathering system, and related water and condensate infrastructure, was expanded in the Carthage area to handle the continued growth associated with the liquids-rich Haynesville natural-gas production. Additionally, Anadarko has secured access to 430 MMcf/d of firm-processing capacity for the Company's current and future development in East Texas.

Marcellus In the Marcellus shale, Anadarko continued to expand its gathering system in Lycoming County, Pennsylvania. In 2014, the Company connected 44 Anadarko-operated wells and constructed 52 miles of new pipeline. The Seely West trunk line, completed in December 2014, connects the COP 356/357 gathering system and Larry's Creek gathering system to the Seely gathering system and alleviates the need to use third parties to gather natural gas.

Springfield In September 2014, the Company sold the Springfield gathering system located in East Texas to a third party.

San Juan In April 2014, the Company sold the San Juan gathering system located in New Mexico, Colorado, and Utah along with the San Juan River gas processing plant located in New Mexico to a third party.

The following provides information regarding the Company's midstream assets by geographic regions:

Area	Asset Type	Miles of Gathering Pipelines		Total Horsepower	2014 Average Net Throughput (MMcf/d)
Rocky Mountains	Gathering, processing, and treating	11,900		1,244,100	3,800
Texas	Gathering, processing, and treating	3,600	&bbsp;	248,400	1,100
Mid-Continent and other	Gathering	3,300		392,200	1,100
Total		18,800		1,884,700	6,000

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's natural-gas, oil, condensate, and NGLs sales, as well as the Company's anticipated LNG sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of natural gas, oil, condensate, and NGLs are generally made at market prices for those products at the time of sale. The Company also purchases natural gas, oil, condensate, and NGLs from third parties, primarily near Anadarko's production areas, to aggregate volumes so that the Company is positioned to fully use transportation, storage and fractionation capacity, facilitate efforts to maximize prices received, and minimize balancing issues with customers and pipelines during operational disruptions.

The Company sells its products under a variety of contract structures including indexed, fixed-price, and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of natural gas, oil, condensate, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to natural-gas, oil, NGLs, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell natural gas, oil, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying natural-gas and oil reserves). See *Commodity-Price Risk* under Item 7A of this Form 10-K.

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Natural Gas Anadarko markets its natural-gas production to maximize value and to reduce the inherent risks of physical commodity markets. Anadarko's marketing segment offers supply-assurance and limited risk-management services at competitive prices, as well as other services that are tailored to its customers' needs. The Company may also receive a service fee related to the level of reliability and service required by the customer. The Company controls natural-gas firm-transportation capacity that ensures access to downstream markets, which enables the Company to maximize its natural-gas production. This transportation capacity also provides the opportunity to capture incremental value when price differentials between physical locations exist. The Company stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical-delivery or financial derivative instruments) to sell stored natural gas at a fixed price.

Oil, Condensate, and NGLs Anadarko's oil, condensate, and NGLs revenues are derived from production in the United States, Algeria, and Ghana. Most of the Company's U.S. oil and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Product from Algeria is sold by tanker as Saharan Blend, condensate, refrigerated propane, and refrigerated butane to customers primarily in the Mediterranean area. Saharan Blend is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel. Oil from Ghana is sold by tanker as Jubilee Oil to customers around the world. Jubilee Oil is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel. Prior to the Company divesting its subsidiary in August 2014, oil from China was sold by tanker as Cao Fei Dian Blend to customers primarily in the Far East markets.

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers.

SEGMENT INFORMATION

For additional information on operations by segment, see *Note 20-Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and for additional information on risk associated with international operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

The Company had approximately 6,100 employees at December 31, 2014.

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REGULATORY AND ENVIRONMENTAL MATTERS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous international, provincial, federal, regional, state, tribal, and local environmental and occupational health and safety laws and regulations. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring, and reporting requirements
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters
- the U.S. Oil Pollution Act of 1990 (OPA), which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur
- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes
- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas

These laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on hydraulic fracturing, ozone standards, climate change, including methane or other greenhouse gas emissions, and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve.

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Many states and foreign countries where the Company operates also have, or are developing, similar environmental laws, regulations, or analogous controls governing many of these same types of activities. While the legal requirements may be similar in form, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business. In addition, environmental laws and regulations, including those that may arise to address potential air and water impacts, are expected to continue to have an increasing impact on the Company's operations in the United States and in other countries in which Anadarko operates.

The Company has reviewed its potential responsibilities under both OPA and CWA as they relate to the Deepwater Horizon events.

As of the date of filing this Form 10-K with the SEC, no penalties or fines have been assessed by the federal government against the Company under OPA, CWA, and other similar local, state and federal environmental legislation related to the Deepwater Horizon events. However, in December 2010, the U.S. Department of Justice, on behalf of the United States, filed a civil lawsuit in the U.S. District Court in New Orleans, Louisiana, against several parties, including the Company, seeking (i) an assessment of civil penalties under the CWA in an amount to be determined by the court, and (ii) a declaratory judgment that such parties are jointly and severally liable without limitation under OPA for all removal costs and damages resulting from the Deepwater Horizon events. For additional information, see *Note 17-Contingencies-Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company has made and will continue to make operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. These are necessary business costs in the Company's operations and in the oil and natural-gas industry. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations, as well as claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to Anadarko. The Company believes that it is in material compliance with existing environmental and occupational health and safety regulations. Further, the Company believes that the cost of maintaining compliance with these existing laws and regulations will not have a material adverse effect on its business, financial condition, results of operations, or cash flows, but new or more stringently applied existing laws and regulations could increase the cost of doing business, and such increases could be material.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the federal Bureau of Safety and Environmental Enforcement (BSEE) regulations, which, among other standards, require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill, identify contracted spill-response equipment, materials and trained personnel, and stipulate the time necessary to deploy identified resources in the event of a spill. The BSEE regulations may be amended, resulting in changes to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change to satisfy any new regulatory requirements, or to adapt to changes in the Company's operations.

Anadarko has in place and maintains both Regional (Central and Western Gulf of Mexico) and Sub-Regional (Eastern Gulf of Mexico) Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans detail procedures for a rapid and effective response to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed at least annually and updated as necessary. Drills are conducted at least annually to test the effectiveness of the Plans and include the participation of spill-response contractors, representatives of Clean Gulf Associates (CGA, a not-for-profit association of production and pipeline companies operating in the Gulf of Mexico contractually engaged by the Company for such matters), and representatives of relevant governmental agencies. The Plans must be approved by the BSEE.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in CGA, and has an employee representative on the executive committee of CGA. CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico. CGA equipment and capabilities include skimming vessels, barges, boom and dispersants, among others. CGA has executed a support contract with T&T Marine to coordinate bareboat charters and provides for expanded response support. T&T Marine is responsible for inspecting, maintaining, storing, and calling out CGA equipment. T&T Marine has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico. T&T Marine also handles the maintenance and mobilization of CGA non-marine equipment. T&T Marine has service contracts in place with domestic environmental contractors as well as with other companies that provide support services during the execution of spill-response activities.

Anadarko is also a member of the Marine Preservation Association, which provides full access to the Marine Spill Response Corporation (MSRC) cooperative including the Deep Blue enhanced Gulf of Mexico Response capability. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials. MSRC has a fleet of dedicated Responder Class Oil Spill-Response Vessels (OSRVs), designed and built specifically to recover spilled oil.

MSRC has equipment housed for the Atlantic Region, the Gulf of Mexico Region, the California Region, and the Pacific Northwest Region. Their equipment includes skimmers, OSRVs, fast response vessels, barges, storage bladders, work boats, ocean boom, and dispersant.

The Company has also entered into a contractual commitment to access subsea intervention, containment, capture, and shut-in capacity for deepwater exploration wells. Marine Well Containment Company (MWCC) is open to all oil and gas operators in the Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis. Anadarko has an employee representative on the executive committee of MWCC and this employee currently serves as its Chair. MWCC members have access to a containment system that is planned for use in deepwater depths of up to 10,000 feet with containment capacity of 100 MBbls/d of liquids and flare capability for 200 MMcf/d of natural gas.

Anadarko retains geospatial and satellite imagery services through the MDA Corporation (MDA) to provide coverage over the Company's Gulf of Mexico operations. MDA owns and maintains two radar satellites, which provide all-weather surveillance and imagery available to assist in identifying areas of concern on the surface waters of the Gulf of Mexico. The Company has agreements with Waste Management, Inc. and Clean Harbors to assist in the proper disposal of contaminated and hazardous waste soil and debris. In addition, Anadarko has agreements with HDR Engineering, Inc. for assistance with Subsea Dispersant applications. The Company also has agreements with TDI-Brooks International for its scientific research vessels to properly monitor the effectiveness of the dispersant application and the health of the ecosystem. The Company also has agreements with Scientific and Environmental Associates, Inc. (SEA) for assistance with surface-dispersant applications. SEA is a scientific support consulting firm providing subject matter experts, and is renowned for its expertise in surface-dispersion applications and efficacy monitoring.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan satisfies the requirements of relevant local or national authority, describes the actions the Company will take in the event of an incident, is subject to drills at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London.

OSRL has an aircraft available for dispersant application or equipment transport. OSRL also has a number of active recovery boom systems, and a range of booms that can be used for offshore, nearshore, or shoreline responses. In addition, OSRL provides a range of communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, power packs and generators, small inflatable vessels, rigid inflatable boats, work boats, and Fast Response Vessels. OSRL also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

In addition to Anadarko's membership in or access to CGA, MSRC, OSRL, and MWCC, the Company participates in industry-wide task forces, which are currently studying improvements in both gaining access to and controlling blowouts in subsea environments. Two such task forces are the Subsea Well Control and Containment Task Force, and the Oil Spill Task Force.

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TITLE TO PROPERTIES

As is customary in the oil and gas industry, a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, thorough title examinations of the drill site tract are conducted by third-party attorneys and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age at January 31, 2015	Position
R. A. Walker	57	Chairman, President and Chief Executive Officer
Robert P. Daniels	56	Executive Vice President, International and Deepwater Exploration
Robert G. Gwin	51	Executive Vice President, Finance and Chief Financial Officer
James J. Kleckner	57	Executive Vice President, International and Deepwater Operations
Charles A. Meloy	54	Executive Vice President, U.S. Onshore Exploration and Production
Robert K. Reeves	57	Executive Vice President, General Counsel and Chief Administrative Officer
M. Cathy Douglas	58	Senior Vice President, Chief Accounting Officer and Controller

Mr. Walker was named Chairman of the Board of the Company in May 2013, in addition to the role of Chief Executive Officer and director, both of which he assumed in May 2012, and the role of President, which he assumed in February 2010. He previously served as Chief Operating Officer from March 2009 until his appointment as Chief Executive Officer. He served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until March 2009. From August 2007 until March 2013, he served as director of Western Gas Holdings, LLC (WGH), the general partner of WES, and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of Western Gas Equity Holdings, LLC (WGEH), the general partner of WGP, from September 2012 until March 2013. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and has served as a director of CenterPoint Energy, Inc. since April 2010 and as a director of BOK Financial Corporation since April 2013.

Mr. Daniels was named Executive Vice President, International and Deepwater Exploration in May 2013 and previously served as Senior Vice President, International and Deepwater Exploration since July 2012. Prior to these positions, he served as Senior Vice President, Worldwide Exploration since December 2006 and served as Senior Vice President, Exploration and Production since May 2004. Prior to that position, he served as Vice President, Canada since July 2001. Mr. Daniels also served in various managerial roles in the Exploration Department for Anadarko Algeria Company, LLC. He has worked for the Company since 1985.

Mr. Gwin was named Executive Vice President, Finance and Chief Financial Officer in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer since March 2009 and Senior Vice President since March 2008. He also has served as Chairman of the Board of WGH since October 2009 and as a director since August 2007. Additionally, Mr. Gwin has served as Chairman of the Board of WGEH since September 2012, and served as President of WGH from August 2007 to September 2009 and as Chief Executive Officer of WGH from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. He has served as Chairman of the Board of LyondellBasell Industries N.V. since August 2013 and as a director since May 2011.

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Mr. Kleckner was named Executive Vice President, International and Deepwater Operations in May 2013. Prior to this position, he served as Vice President, Operations for the Rockies region since May 2007. Mr. Kleckner joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, including management roles in the North Sea, South America, China, the Gulf of Mexico and U.S. onshore. Prior to joining Kerr-McGee Corporation, Mr. Kleckner was in the oil and natural-gas industry with Oryx Energy Company and its predecessor, Sun Oil Company.

Mr. Meloy was named Executive Vice President, U.S. Onshore Exploration and Production in May 2013 and previously served as Senior Vice President, U.S. Onshore Exploration and Production since July 2012. Prior to this position, he served as Senior Vice President, Worldwide Operations since December 2006 and served as Senior Vice President, Gulf of Mexico and International Operations since the acquisition of Kerr-McGee Corporation in August 2006. Prior to joining Anadarko, he served Kerr-McGee Corporation as Vice President of Exploration and Production from 2005 to 2006, Vice President of Gulf of Mexico Exploration, Production and Development from 2004 to 2005, Vice President and Managing Director of Kerr-McGee North Sea (U.K.) Limited from 2002 to 2004 and Vice President of Gulf of Mexico Deepwater from 2000 to 2002. Prior to joining Kerr-McGee Corporation, Mr. Meloy was in the oil and natural-gas industry with Oryx Energy Company and its predecessor, Sun Oil Company. Mr. Meloy has served as a director of WGH since February 2009 and as a director of WGEH since September 2012.

Mr. Reeves was named Executive Vice President, General Counsel and Chief Administrative Officer in May 2013 and previously served as Senior Vice President, General Counsel and Chief Administrative Officer since February 2007. He also served as Chief Compliance Officer from July 2012 to May 2013. He served as Corporate Secretary from February 2007 to August 2008. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer since 2004. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004, and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. He has served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, since October 2007, as a director of WGH since August 2007 and as a director of WGEH since September 2012.

Ms. Douglas was named Senior Vice President, Chief Accounting Officer and Controller in May 2013. Prior to this position, she served as Vice President and Chief Accounting Officer since November 2008 and served as Corporate Controller from September 2007 to March 2009 and from March 2013 to May 2013. She served as Assistant Controller from July 2006 to September 2007. She also served as Director, Accounting, Policy and Coordination from October 2006 to September 2007 and Financial Reporting and Policy Manager from January 2003 to October 2006. Ms. Douglas joined Anadarko in 1979.

Officers of Anadarko are elected each year at the first meeting of the Board of Directors following the annual meeting of stockholders, the next of which is expected to occur on May 12, 2015, and hold office until their successors are duly elected and qualified. There are no family relationships between any directors or executive officers of Anadarko.

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Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this report, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *reserves levels*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of natural gas, oil, natural gas liquids (NGLs), and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions, either nationally, internationally, or in the jurisdictions in which the Company or its subsidiaries are doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations*

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- *the ability of BP Exploration & Production Inc. (BP) to meet its indemnification obligations to the Company for Deepwater Horizon events, including, among other things, damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the Operating Agreement (OA) for the Macondo well, as well as the ability of BP Corporation North America Inc. (BPCNA) and BP p.l.c. to satisfy their guarantees of such indemnification obligations*
- *the impact of remaining claims related to the Deepwater Horizon events, including, but not limited to, fines, penalties, and punitive damages against the Company, for which it is not indemnified by BP*
- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay its debt, and the impact of changes in the Company's credit ratings*
- *disruptions in international oil, NGLs, and condensate cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in this Form 10-K, and in the Company's other public filings, press releases, and discussions with Company management*

RISK FACTORS

We may be subject to claims and liabilities relating to the Deepwater Horizon events that are not covered by BP's indemnification obligations under our Settlement Agreement with BP, or that result in losses to the Company, notwithstanding BP's indemnification against such losses, as a result of BP's inability to satisfy its indemnification obligations under the Settlement Agreement and BPCNA's and BP p.l.c.'s inability to satisfy their guarantees of BP's indemnification obligations.

In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under OPA, NRD claims and assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BPCNA and, in the event that the net worth of BPCNA declines below an agreed-on amount, BP p.l.c. has agreed to become the sole guarantor.

Any failure or inability on the part of BP to satisfy its indemnification obligations under the Settlement Agreement, or on the part of BPCNA or BP p.l.c. to satisfy their respective guarantee obligations, could subject us to significant monetary liability beyond the terms of the Settlement Agreement, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. In November 2012, BP settled all criminal and securities claims brought by the United States against BP, with BP agreeing to pay $4.0 billion over five years to the U.S. Department of Justice with respect to the criminal claims and further agreeing to pay another $525 million over three years to the Securities and Exchange Commission (SEC) with respect to the securities claims. In addition, in September 2014, the U.S. District Court in New Orleans, Louisiana (Louisiana District Court) issued its Findings of Fact and Conclusions of Law in the first phase of the Deepwater Horizon trial. The Louisiana District Court found that BP is liable under general maritime law for the blowout, explosion, and oil spill and apportioned 67% of the fault to BP. BP is challenging certain of the Louisiana District Court's findings.

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Furthermore, in certain instances we may be required to recognize a liability for amounts for which we are indemnified in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. Any such liability recognition without collection of the offsetting receivable could adversely impact our results of operations, our financial condition, and our ability to make borrowings.

Under the Settlement Agreement, BP does not indemnify the Company against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims. The adverse resolution of any current or future proceeding related to the Deepwater Horizon events for which we are not indemnified by BP could subject us to significant monetary liability, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Oil, natural-gas, and NGLs prices are volatile. A substantial or extended decline in the price of these commodities could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. For example, daily settlement prices for New York Mercantile Exchange (NYMEX) West Texas Intermediate oil ranged from a high of $107.26 per barrel to a low of $53.27 per barrel during 2014. Daily settlement prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per million British thermal units (MMBtu) to a low of $2.89 per MMBtu during 2014. Our revenues, operating results, cash flows from operations, capital budget, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatile trading patterns in the commodity-futures markets
- cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- level of global oil and natural-gas inventories
- weather conditions
- potential U.S. exports of liquefied natural gas, oil, condensate, or NGLs
- ability of the members of the Organization of the Petroleum Exporting Countries (OPEC) and other producing nations to agree to and maintain production levels
- worldwide military and political environment, civil and political unrest in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or further acts of terrorism in the United States or elsewhere
- effect of worldwide energy conservation and environmental protection efforts
- price and availability of alternative and competing fuels
- price and level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental laws, regulations, and taxes
- proximity to, and capacity of, natural-gas pipelines and other transportation facilities
- general economic conditions worldwide

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs is uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations
- reducing the amount of oil, natural gas, and NGLs that we can produce economically
- causing us to delay or postpone some of our capital projects

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- reducing our revenues, operating income, or cash flows
- reducing the amounts of our estimated proved oil, natural-gas, and NGLs reserves
- reducing the carrying value of our oil and natural-gas properties
- reducing the standardized measure of discounted future net cash flows relating to oil, natural-gas, and NGLs reserves
- limiting our access to, or increasing the cost of, sources of capital, such as equity and long-term debt

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, provincial, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, hydraulic fracturing, and environmental protection regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, provincial, regional, state, tribal, and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations. Our costs of compliance may increase if existing laws, including environmental and tax laws and regulations, are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, from time to time, legislation has been proposed that could adversely affect our business, financial condition, results of operations, or cash flows related to the following:

- *Ozone Standards.* In December 2014, the U.S. Environmental Protection Agency (EPA) published proposed regulations to revise the National Ambient Air Quality Standard for ozone, recommending a standard between 65 to 70 parts per billion (ppb) for both the 8-hour primary and secondary standards protective of public health and public welfare. The current primary and secondary ozone standards are set at 75 ppb. The EPA is also taking comments on whether a 60 ppb standard should be established for the primary standard or whether the existing 75 ppb standard should be retained. If adopted, compliance with such regulations may require the Company to install new equipment to further control emissions and may also cause permitting delays. The EPA currently expects to issue a final rule by October 1, 2015.
- *Reduction of Methane Emissions.* In January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will regulate methane emissions from the oil and gas sector. The Obama Administration seeks to reduce methane emissions from new and modified infrastructure and equipment in the oil and gas sector, including the drilling of new wells, by up to 45% from 2012 levels by 2025.
- *Climate Change.* A number of state and regional efforts exist that are aimed at tracking or reducing greenhouse gas (GHG) emissions. In addition, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that restrict emissions of GHGs under existing provisions of the Clean Air Act. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. We may be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants.
- *Deficit Reduction or Tax Reform.* Congress may undertake significant deficit reduction or comprehensive tax reform in the coming year. Proposals include provisions that would, if enacted, (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) eliminate the manufacturing deduction for oil and gas qualified production activities, and (iii) eliminate accelerated depreciation for tangible property.

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Changes in laws or regulations regarding hydraulic fracturing or other oil and gas operations could increase our costs of doing business, impose additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of natural gas and oil from dense subsurface rock formations such as shales. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing is regulated by state oil and natural-gas commissions. However, several federal agencies have also asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards for the oil and gas industry; announced its intent to propose in early 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the Bureau of Land Management issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is expected to promulgate a final rule in early 2015. Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, or well-construction requirements on hydraulic-fracturing operations or prohibit these operations completely. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. For example, in exchange for the withdrawal of several initiatives relating to hydraulic fracturing and other oil and gas operations proposed for inclusion on the Colorado state ballot in November 2014, the governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations (Task Force) in September 2014 to make recommendations to the state legislature regarding the responsible development of Colorado's oil and gas resources. Although it is early in the process, it is possible that, as a result of the Task Force's recommendations, Colorado could adopt new policies or legislation relating to oil and natural-gas operations, including measures that would give local governments in Colorado greater authority to limit hydraulic fracturing and other oil and natural-gas operations or require greater distances between well sites and occupied structures. In the event state or local restrictions or prohibitions are adopted in areas where we conduct operations, such as the Wattenberg field in Colorado, we may incur significant costs to comply with such requirements or we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Such costs, delays, restrictions, or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

In addition to asserting regulatory authority, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding "unconventional natural-gas production," including hydraulic fracturing. In December 2012, the EPA issued an initial progress report on a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment in early 2015. These studies and initiatives, or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

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Our debt and other financial commitments may limit our financial and operating flexibility.

Our total debt was $15.1 billion at December 31, 2014. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business including, but not limited to, the following:

- increasing our vulnerability to general adverse economic and industry conditions
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments

Additionally, the credit agreements governing our $3.0 billion five-year senior unsecured revolving credit facility and our $2.0 billion 364-day senior unsecured revolving credit facility contain a number of customary covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65%, and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. Our ability to meet such covenants may be affected by events beyond our control.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2014, our long-term debt was rated "BBB" with a stable outlook by Standard and Poor's (S&P), "BBB-" with a positive outlook by Fitch Ratings (Fitch), and "Baa3" with a positive outlook by Moody's Investors Service (Moody's). In February 2015, Moody's raised our long-term debt rating to "Baa2" and changed the outlook to stable. Although we are not aware of any current plans of S&P, Fitch, or Moody's to lower their respective ratings on our debt, we cannot be assured that our credit ratings will not be downgraded. A downgrade in our credit ratings could negatively impact our cost of capital or our ability to effectively execute aspects of our strategy. If our credit ratings were downgraded, it could affect our ability to raise debt in the public debt markets and the cost of that new debt could be much higher than our outstanding debt. In addition, a downgrade could affect the Company's requirements to provide financial assurance of its performance under certain contractual arrangements and derivative agreements. See *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserves information included or incorporated by reference in this report represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserves audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil and natural-gas reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates. These factors and assumptions may include, but are not limited to, the following:

- historical production from an area compared with production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil and natural-gas prices, future operating costs, and capital expenditures
- estimates of future severance and excise taxes, workover costs, and remedial costs

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Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this report should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average beginning-of-month prices during the 12-month period for the respective year. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves.

Failure to replace reserves may negatively affect our business.

Our future success depends on our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities, acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A portion of our leasehold acreage is currently undeveloped. Unless production in sufficient quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based on various factors: drilling results, oil and natural-gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

Future economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, potential default on U.S. debt, energy costs, geopolitical issues, the availability and cost of credit, and uncertainties with regard to European sovereign debt, have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. Continued concerns could cause demand for petroleum products to diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs; affect the ability of our vendors, suppliers, and customers to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we had approximately $5.6 billion of goodwill on our Consolidated Balance Sheet at December 31, 2014. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could lead to an impairment of goodwill, such as the Company's inability to replace the value of its depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events, such as lower oil and natural-gas prices, which could reduce the fair value of the associated reporting unit. An impairment of goodwill could have a substantial negative effect on our profitability.

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We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous federal, provincial, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling, production, and midstream activities
- protection of endangered species
- amounts and types of emissions and discharges
- generation, management, and disposition of waste materials
- offshore oil and gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites

In addition, these laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Future environmental laws and regulations, such as the restriction against emission of pollutants from previously unregulated activities or the designation of previously unprotected species as threatened or endangered in areas where we operate, such as the sage grouse, may negatively impact our operations. The cost of satisfying these requirements may have an adverse effect on our financial condition, results of operations, or cash flows or could result in limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce our reserves. For a description of certain environmental proceedings in which we are involved, see *Legal Proceedings* under Item 3 and *Note 17-Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Mozambique, Ghana, Brazil, Colombia, Côte d'Ivoire, Kenya, Liberia, New Zealand, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas because we are vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

- hurricanes and other adverse weather conditions
- oilfield service costs and availability

&28226;compliance with environmental and other laws and regulations

- terrorist attacks, such as piracy
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
- failure of equipment or facilities

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations and decommissioning activities are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in its shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

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Further, production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production and, as a result, our reserves replacement needs from new prospects may be greater there than for our operations elsewhere. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods.

Additional domestic and international deepwater drilling laws, regulations, and other restrictions; delays in the processing and approval of drilling permits and exploration and oil spill-response plans; and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010, the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement, each agencies of the U.S. Department of the Interior, imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these new and more stringent rules and regulations, in addition to uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits and exploration, development, and oil spill-response plans, and possible additional regulatory initiatives could adversely affect or delay new drilling and ongoing development efforts. Among other adverse impacts, these additional measures could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities. If similar material spill events were to occur in the future, the United States or other countries could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite the Company's oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Deepwater Horizon incident.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We operate in foreign countries and are subject to political, economic, and other uncertainties.

Our operations outside the United States are based primarily in Algeria, Brazil, Colombia, Côte d'Ivoire, Ghana, Kenya, Liberia, Mozambique, and New Zealand. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include the following, among other things:

- loss of revenue, property, and equipment or delays in operations as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks, including tension and confrontations among political parties
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance laws and issues
- increases in taxes and governmental royalties
- unilateral renegotiation of contracts by governmental entities
- redefinition of international boundaries or boundary disputes
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations
- changes in laws and policies governing operations of foreign-based companies

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- foreign-exchange restrictions
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business

For example, Ghana and Côte d'Ivoire are engaged in a dispute regarding the international maritime and land boundaries between the two countries. As a result, Côte d'Ivoire claims to be entitled to the maritime area which covers a portion of the Deepwater Tano Block where we are developing the TEN complex. In the event Côte d'Ivoire is successful in its maritime border claims, this development could be materially impacted. Also, Venezuela and Guyana are in a dispute regarding their maritime and land borders in which the two countries have initiated a dialogue. We are unable to ascertain the full impact of this border dispute on future operations in Guyana.

Outbreaks of civil and political unrest and acts of terrorism have occurred in countries in Europe, Africa, and the Middle East, including countries where we conduct operations. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired.

Our international operations may also be adversely affected, directly or indirectly, by laws, policies, and regulations of the United States affecting foreign trade and taxation, including U.S. trade sanctions.

Realization of any of the factors listed above could materially and adversely affect the Company's financial condition, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volumes
- a widening of price basis differentials occurs between delivery points for our production and the delivery point assumed in the derivative arrangement
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements
- a sudden unexpected event materially impacts oil, natural-gas, or NGLs prices

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market including swap clearing and trade execution requirements. While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed margin rules, position limits, and commodity clearing requirements, remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time.

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New or modified rules, regulations, or legal requirements may increase the cost and impact the availability to our counterparties of their hedging and swap positions that they can make available to us, and may further require the counterparties to our derivative instruments to spin off some of their derivative activities to separate entities, which may not be as creditworthy as the current counterparties. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation or post margin collateral. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity-price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, (iii) reduce the availability of derivatives to protect against risks we encounter, and (iv) increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent the Company transacts with counterparties in foreign jurisdictions, it may become subject to such regulations. At this time, the impact of such regulations is not clear.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility. Moreover, to the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time.

We are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and gas, including blowouts; cratering and fire; environmental hazards, such as gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property; pollution or other environmental damage; and injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/loss of control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial condition, results of operations, or cash flows.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects and the completion of those projects may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of such projects include the following:

- project approvals by joint-venture partners
- timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
- weather conditions
- availability of qualified personnel
- civil and political environment of, and existing infrastructure in, the country or region in which the project is located
- manufacturing and delivery schedules of critical equipment
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects and could have a material adverse effect on our results of operations.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies, as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources on which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

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Our drilling activities may not be productive.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including the following:

- unexpected drilling conditions
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts, and surface cratering
- marine risks such as capsizing, collisions, and hurricanes
- difficulty identifying and retaining qualified personnel
- title problems
- other adverse weather conditions
- shortages or delays in the delivery of equipment

Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of our capital budget devoted to high-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

We have limited influence over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence the operation or future development of these nonoperated properties or the amount of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital, lead to unexpected future costs, or adversely affect the timing of activities.

Our ability to sell our oil, natural gas, and NGLs production could be materially harmed if we fail to obtain adequate services such as transportation.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities and tanker transportation. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil, natural gas, and NGLs, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and gas.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, which could have an adverse effect on our reputation, financial condition, results of operations, or cash flows.

While we have experienced cybersecurity attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity vulnerabilities.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. The amount of cash dividends, if any, to be paid in the future will depend on actions taken by our Board of Directors, as well as, our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other related matters that our Board of Directors deems relevant.

The loss of key members of our management team, or difficulty attracting and retaining experienced technical personnel, could reduce our competitiveness and prospects for future success.

The successful implementation of our strategies and handling of other issues integral to our future success will depend, in part, on our experienced management team. The loss of key members of our management team could have an adverse effect on our business. We do not carry key man insurance. Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

None.

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Item 3. Legal Proceedings

GENERAL The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

In September 2013, Anadarko received a Notice of Proposed Penalty Assessment from the Bureau of Safety and Environmental Enforcement (BSEE) as the result of an incident that occurred in February 2012 relating to a drilling rig in the Gulf of Mexico. In the notice, BSEE alleged several violations of certain offshore operational requirements. Anadarko disputed many of the allegations and in October 2014 received a Revised Final Reviewing Officer's Decision from BSEE for a penalty of $70,000.

In June 2014, the EPA alleged that Anadarko was not in compliance with a consent decree entered into by the U.S. District Court for the District of Colorado on March 27, 2008 to resolve certain Clean Air Act violations in Colorado and Utah. Specifically, the EPA alleged violations of the consent decree at three of Anadarko's compressor station facilities located in Utah. In November 2014, Anadarko entered into a joint stipulation with the EPA and agreed to pay a penalty of $599,000.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA concerning enforcement for alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 17-Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5.Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

At January 30, 2015, there were approximately 11,400 holders of record of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange. The following shows information regarding the market price of and dividends declared and paid on the Company's common stock by quarter for 2014 and 2013:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2014				
Market Price				
High	**$ 86.86**	**$ 112.06**	**$ 113.51**	**$ 102.68**
Low	**$ 77.80**	**$ 84.54**	**$ 100.40**	**$ 71.00**
Dividends	**$ 0.18**	**$ 0.27**	**$ 0.27**	**$ 0.27**
2013				
Market Price				
High	$ 89.20	$ 92.18	$ 96.75	$ 98.47
Low	$ 74.73	$ 78.30	$ 86.08	$ 73.60
Dividends	$ 0.09	$ 0.09	$ 0.18	$ 0.18

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with its financial covenants, and other factors, and will be determined by the Board of Directors on a quarterly basis. For additional information, see *Liquidity and Capital Resources-Uses of Cash-Common Stock Dividends and Distributions to Noncontrolling Interest Owners* under Item 7 of this Form 10-K.

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SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2014:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	6,791,018	$ 69.96	21,169,470
Equity compensation plans not approved by security holders	-	-	-
Total	6,791,018	$ 69.96	21,169,470

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2014:

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
October	14,821	$ 92.69	-	
November	79,151	$ 92.83	-	
December	2,084	$ 77.60	-	
Fourth Quarter 2014	96,056	$ 92.48	-	$ -

(1) During the fourth quarter of 2014, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances.

For additional information, see *Note 15-Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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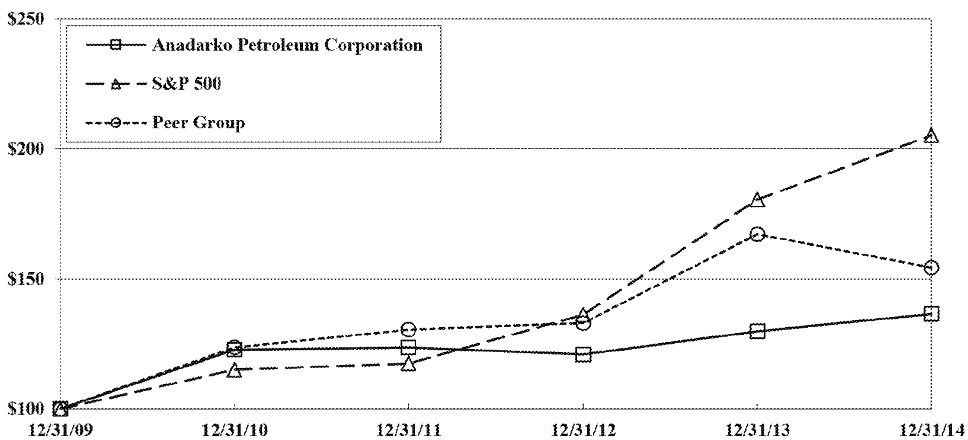
PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders of Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a peer group of 11 companies. The companies included in the peer group are Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Murphy Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company.

Comparison of 5-Year Cumulative Total Return Among Anadarko Petroleum Corporation, the S&P 500 Index, and a Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the S&P 500 Index, and in the peer group on December 31, 2009, and its relative performance is tracked through December 31, 2014.

Fiscal Year Ended December 31	2009	2010	2011	2012	2013	2014
Anadarko Petroleum Corporation	$ 100.00	$ 122.78	$ 123.64	$ 120.97	$ 129.92	$ 136.59
S&P 500	100.00	115.06	117.49	136.30	180.44	205.14
Peer Group	100.00	123.66	130.54	133.12	167.31	154.38

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Item 6. Selected Financial Data

	Summary Financial Information [1]				
millions except per-share amounts	**2014**	2013	2012	2011	2010
Sales Revenues	**$ 16,375**	$ 14,867	$ 13,307	$ 13,882	$ 10,842
Gains (Losses) on Divestitures and Other, net	**2,095**	(286)	104	85	142
Total Revenues and Other	**18,470**	14,581	13,411	13,967	10,984
Algeria Exceptional Profits Tax Settlement	**-**	33	(1,797)	-	-
Deepwater Horizon Settlement and Related Costs	**97**	15	18	3,930	15
Operating Income (Loss)	**5,403**	3,333	3,727	(1,870)	1,769
Tronox-related Contingent Loss	**4,360**	850	(250)	250	-
Income (Loss)	**(1,563)**	941	2,445	(2,568)	821
Net Income (Loss) Attributable to Common Stockholders	**(1,750)**	801	2,391	(2,649)	761
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)-Basic	**$ (3.47)**	$ 1.58	$ 4.76	$ (5.32)	$ 1.53
Net Income (Loss)-Diluted	**$ (3.47)**	$ 1.58	$ 4.74	$ (5.32)	$ 1.52
Dividends	**$ 0.99**	$ 0.54	$ 0.36	$ 0.36	$ 0.36
Average Number of Common Shares Outstanding-Basic	**506**	502	500	498	495
Average Number of Common Shares Outstanding-Diluted	**506**	505	502	498	497
Cash Provided by Operating Activities	**8,466**	8,888	8,339	2,505	5,247
Capital Expenditures	**$ 9,256**	$ 8,523	$ 7,311	$ 6,553	$ 5,169
Current Portion of Long-term Debt	**$ -**	$ 500	$ -	$ 170	$ 291
Long-term Debt	**15,092**	13,065	13,269	15,060	12,722
Total Debt	**$ 15,092**	$ 13,565	$ 13,269	$ 15,230	$ 13,013
Total Stockholders' Equity	**19,725**	21,857	20,629	18,105	20,684
Total Assets	**$ 61,689**	$ 55,781	$ 52,589	$ 51,779	$ 51,559
Annual Sales Volumes					
Natural Gas (Bcf)	**945**	968	913	852	829
Oil and Condensate (MMBbls)	**106**	91	86	79	74
Natural Gas Liquids (MMBbls)	**44**	33	30	27	23
Total (MMBOE)[2]	**308**	285	268	248	235
Average Daily Sales Volumes					
Natural Gas (MMcf/d)	**2,589**	2,652	2,495	2,334	2,272
Oil and Condensate (MBbls/d)	**292**	248	233	217	201
Natural Gas Liquids (MBbls/d)	**119**	91	83	74	63
Total (MBOE/d)	**843**	781	732	680	643
Proved Reserves					
Natural-gas Reserves (Tcf)	**8.7**	9.2	8.3	8.4	8.1
Oil and Condensate Reserves (MMBbls)	**929**	851	767	771	749
Natural-gas Liquids Reserves (MMBbls)	**479**	407	405	374	320
Total Proved Reserves (MMBOE)	**2,858**	2,792	2,560	2,539	2,422
Number of Employees	**6,100**	5,700	5,200	4,800	4,400

[1] Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.
[2] Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

Table of Measures

Bcf-Billion cubic feet

MMBbls-Million barrels

MMBOE-Million barrels of oil equivalent

MMcf/d-Million cubic feet per day

MBbls/d-Thousand barrels per day

MBOE/d-Thousand barrels of oil equivalent per day

Tcf-Trillion cubic feet

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this report in Item 8, and the information set forth in *Risk Factors* under Item 1A. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

OVERVIEW

Anadarko met or exceeded its key operational objectives in 2014. The Company increased sales volumes per day by approximately 8% over 2013 and added 502 million barrels of oil equivalent (MMBOE) of proved reserves. The Company ended 2014 with $7.4 billion of cash on hand, full availability of its $5.0 billion senior secured revolving credit facility maturing in September 2015 ($5.0 billion Facility), and access to credit and capital markets as needed.

In January 2015, the Company paid $5.2 billion after the settlement agreement resolving all claims asserted in the Tronox Adversary Proceeding became effective and replaced the $5.0 billion Facility with two new unsecured credit facilities. The Company paid the settlement using cash on hand and borrowings. Management believes that the Company is positioned to continue to satisfy its operational objectives and capital commitments with cash on hand, available borrowing capacity, and cash flows from operations.

Mission and Strategy

Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko employs the following strategy to achieve this mission:

- explore in high-potential, proven basins
- identify and commercialize resources
- employ a global business development approach
- ensure financial discipline and flexibility

Exploring in high-potential, proven, and emerging basins worldwide provides the Company with growth opportunities. Anadarko's exploration success has created value by increasing future resource potential, while providing the flexibility to mitigate risk by monetizing discoveries.

Developing a portfolio of primarily unconventional resources provides the Company a stable base of capital-efficient and predictable development opportunities that, in turn, positions the Company for consistent growth at competitive rates.

Anadarko's global business development approach transfers core skills across the globe to assist in the discovery and development of world-class resources that are accretive to the Company's performance. These resources help form an optimized global portfolio where both surface and subsurface risks are actively managed.

A strong balance sheet is essential for the development of the Company's assets, and Anadarko is committed to disciplined investment in its businesses to efficiently manage commodity price cycles. Maintaining financial discipline enables the Company to capitalize on the opportunities afforded by its global portfolio, while allowing the Company to pursue new strategic growth opportunities.

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Significant 2014 operating and financial activities include the following:

Overall

- Anadarko's full-year sales volumes averaged 843 thousand barrels of oil equivalent per day (MBOE/d), representing an 8% increase over 2013.
- Anadarko's liquids sales volumes were 411 thousand barrels per day (MBbls/d), representing a 21% increase over 2013, primarily due to increased sales volumes in the Wattenberg field, the Eagleford shale, and the Delaware basin.
- The Company's overall sales product mix increased to 49% liquids in 2014 compared to 43% in 2013.
- Anadarko and Kerr-McGee Corporation and certain of its subsidiaries entered into a settlement agreement resolving all claims asserted in the Tronox Adversary Proceeding resulting in a payment of $5.2 billion, including interest, in January 2015. See *Note 17-Contingencies-Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

U.S. Onshore

- The Rocky Mountains Region (Rockies) full-year sales volumes averaged 361 MBOE/d, representing a 10% increase over 2013, primarily from the Wattenberg field.
- The Southern and Appalachia Region full-year sales volumes averaged 298 MBOE/d, representing a 16% increase over 2013, primarily from the Marcellus and Eagleford shales, the Delaware basin, and the East Texas/North Louisiana horizontal development.
- Western Gas Partners, LP (WES), a consolidated subsidiary of the Company, acquired Nuevo Midstream, LLC (Nuevo), which owns and operates gathering and processing assets located in the Delaware basin in West Texas, for $1.554 billion. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM).
- The Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas.
- The Company sold its interest in the Pinedale/Jonah assets in Wyoming for $581 million.

Gulf of Mexico

- Gulf of Mexico full-year sales volumes averaged 83 MBOE/d, representing a 14% decrease from 2013, primarily due to natural production declines.
- Anadarko's Lucius development project in the deepwater Gulf of Mexico was completed with first oil achieved in January 2015.
- The Company sold its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for $500 million, recognizing a gain of $237 million.

International

- International full-year sales volumes averaged 92 MBOE/d, representing a 2% increase from 2013, primarily due to increased sales volumes at El Merk in Algeria.
- Anadarko sold a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion, recognizing a gain of $1.5 billion.
- Anadarko sold its Chinese subsidiary for $1.075 billion, recognizing a gain of $510 million.
- The Tweneboa/Enyenra/Ntomme (TEN) project in Ghana was approximately 50% complete and nine development wells had been drilled at year end 2014. First oil is expected in 2016.

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Financial

- Anadarko's net loss attributable to common stockholders for 2014 totaled $1.8 billion, which included a $4.360 billion contingent loss related to the Tronox Adversary Proceeding and $836 million of impairment expense primarily related to certain U.S. onshore and Gulf of Mexico properties.
- The Company generated $8.5 billion of cash flow from operations in 2014 and ended 2014 with $7.4 billion of cash on hand.
- Anadarko increased the quarterly dividend paid to its common stockholders from $0.18 per share to $0.27 per share.
- The Company repaid $775 million of Senior Notes that matured in 2014.
- Anadarko entered into a $3.0 billion five-year senior unsecured revolving credit facility, which is expandable to $4.0 billion, and a $2.0 billion 364-day senior unsecured revolving credit facility. These facilities (collectively, the New Credit Facilities) replaced the $5.0 billion Facility upon satisfaction of certain conditions, including the January 2015 settlement payment related to the Tronox Adversary Proceeding.
- Anadarko issued $625 million aggregate principal amount of 3.450% Senior Notes due 2024 and $625 million aggregate principal amount of 4.500% Senior Notes due 2044.
- The Company sold approximately 6 million Western Gas Equity Partners, LP (WGP) common units to the public, raising net proceeds of $335 million.
- WES entered into a five-year $1.2 billion, expandable to $1.5 billion, senior unsecured revolving credit facility maturing in February 2019 (RCF), which amended and restated its then-existing $800 million senior unsecured revolving credit facility.
- WES completed public offerings of $100 million aggregate principal amount of 2.600% Senior Notes due 2018 and $400 million aggregate principal amount of 5.450% Senior Notes due 2044.
- WES issued approximately 10 million common units to the public, raising total net proceeds of $691 million.

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2014," refer to the comparison of the year ended December 31, 2014, to the year ended December 31, 2013. Similarly, any increases or decreases "for the year ended December 31, 2013," refer to the comparison of the year ended December 31, 2013, to the year ended December 31, 2012. The primary factors that affect the Company's results of operations include commodity prices for natural gas, oil, and natural gas liquids (NGLs); sales volumes; the Company's ability to discover additional reserves; the cost of finding such reserves; and operating costs.

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RESULTS OF OPERATIONS

millions except per-share amounts and percentages		**2014**		2013		2012
Financial Results						
Natural-gas, oil and condensate, and NGLs sales	**$**	**15,169**	$	13,828	$	12,396
Gathering, processing, and marketing sales		**1,206**		1,039		911
Gains (losses) on divestitures and other, net		**2,095**		(286)		104
Total revenues and other		**18,470**		14,581		13,411
Costs and expenses (1)		**13,067**		11,248		9,684
Other (income) expense (2)		**5,349**		1,227		162
Income tax expense (benefit)		**1,617**		1,165		1,120
Net income (loss) attributable to common stockholders	**$**	**(1,750)**	$	801	$	2,391
Net income (loss) per common share attributable to common stockholders-diluted	**$**	**(3.47)**	$	1.58	$	4.74
Average number of common shares outstanding-diluted		**506**		505		502
Operating Results						
Adjusted EBITDAX (3)	**$**	**12,721**	$	9,403	$	8,966
Total proved reserves (MMBOE)		**2,858**		2,792		2,560
Annual sales volumes (MMBOE)		**308**		285		268
Capital Resources and Liquidity						
Cash provided by operating activities	**$**	**8,466**	$	8,888	$	8,339
Capital expenditures		**9,256**		8,523		7,311
Total debt		**15,092**		13,565		13,269
Total equity	**$**	**22,318**	$	23,650	$	21,882
Debt to total capitalization ratio		**40.3%**		36.5%		37.7%

(1) Includes a credit of $1.8 billion in 2012 for previously recognized expenses related to the favorable resolution of the Algeria exceptional profits tax dispute.

(2) Includes Tronox-related contingent loss of $4.360 billion in 2014, $850 million in 2013, and reversal of the 2011 Tronox-related contingent loss $(250) million in 2012.

(3) See *Operating Results-Segment Analysis-Adjusted EBITDAX* for a description of Adjusted EBITDAX, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and for a reconciliation of Adjusted EBITDAX to income (loss) before income taxes, which is the most directly comparable financial measure presented in accordance with GAAP.

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FINANCIAL RESULTS

millions	Natural Gas	Oil and Condensate	NGLs	Total
2013 sales revenues	$ 3,388	$ 9,178	$ 1,262	$ 13,828
Changes associated with prices	**540**	**(1,046)**	**(86)**	**(592)**
Changes associated with sales volumes	**(79)**	**1,616**	**396**	**1,933**
2014 sales revenues	**$ 3,849**	**$ 9,748**	**$ 1,572**	**$ 15,169**
Increase/(Decrease) vs. 2013	**14%**	**6%**	**25%**	**10%**
2012 sales revenues	$ 2,444	$ 8,728	$ 1,224	$ 12,396
Changes associated with prices	798	(85)	(82)	631
Changes associated with sales volumes	146	535	120	801
2013 sales revenues	$ 3,388	$ 9,178	$ 1,262	$ 13,828
Increase/(Decrease) vs. 2012	39%	5%	3%	12%

Anadarko's sales revenues increased for the year ended December 31, 2014, primarily due to higher oil and NGLs sales volumes and higher average natural-gas prices, partially offset by lower average oil and NGLs prices and slightly lower natural-gas sales volumes. Total sales revenues increased for the year ended December 31, 2013, primarily due to higher sales volumes for all products and higher average natural-gas prices, partially offset by lower average oil and NGLs prices.

The following provides Anadarko's sales volumes for the years ended December 31, 2014, 2013, and 2012:

	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Barrels of Oil Equivalent					
(MMBOE except percentages)					
United States	**275**	9%	252	6%	237
International	**33**	2	33	7	31
Total barrels of oil equivalent	**308**	8	285	6	268
Barrels of Oil Equivalent per Day					
(MBOE/d except percentages)					
United States	**751**	9%	691	7%	648
International	**92**	2	90	7	84
Total barrels of oil equivalent per day	**843**	8	781	7	732

Sales volumes represent actual production volumes adjusted for changes in commodity inventories and natural-gas production volumes provided to a certain government entity to satisfy a commitment established in conjunction with the development plan. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and Other (Income) Expense-(Gains) Losses on Derivatives, net. Production of natural gas, oil, and NGLs is usually not affected by seasonal swings in demand.

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Natural-Gas Sales Volumes, Average Prices, and Revenues

	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
United States					
Sales volumes-Bcf	**945**	(2)%	968	6%	913
MMcf/d	**2,589**	(2)	2,652	6	2,495
Price per Mcf	**$ 4.07**	16	$ 3.50	31	$ 2.68
Natural-gas sales revenues (millions)	**$ 3,849**	14	$ 3,388	39	$ 2,444

Bcf-billion cubic feet
MMcf/d-million cubic feet per day
Mcf-thousand cubic feet

Natural-Gas Sales Volumes

2014 vs. 2013 The Company's natural-gas sales volumes decreased by 63 MMcf/d.

- Sales volumes decreased by 90 MMcf/d in the Rockies primarily due to the sale of the Company's Pinedale/Jonah assets in January 2014 and natural production declines in the Powder River basin and Greater Natural Buttes. These decreases were partially offset by higher sales volumes in the Wattenberg field due to increased horizontal drilling.
- Sales volumes decreased by 67 MMcf/d in the Gulf of Mexico primarily due to natural production declines.
- Sales volumes for the Southern and Appalachia Region increased by 94 MMcf/d primarily due to infrastructure expansions that allowed the Company to bring wells online in the Marcellus and Eagleford shales, as well as continued horizontal drilling in the liquids-rich East Texas/North Louisiana horizontal development.

2013 vs. 2012 The Company's natural-gas sales volumes increased by 157 MMcf/d.

- Sales volumes increased by 246 MMcf/d in the Southern and Appalachia Region primarily due to horizontal drilling and infrastructure expansions in the Eagleford and Marcellus shales, as well as new wells drilled in the liquids-rich East Texas/North Louisiana horizontal development.
- Sales volumes decreased by 47 MMcf/d in the Gulf of Mexico primarily due to natural production declines.
- Sales volumes for the Rockies decreased by 42 MMcf/d primarily due to a natural production decline in the Powder River basin, partially offset by higher sales volumes in the Wattenberg field due to increased horizontal drilling.

Natural-Gas Prices

2014 vs. 2013 The average natural-gas price Anadarko received increased primarily due to low industry natural-gas storage levels as a result of colder than average winter temperatures and the associated high residential heating demand in early 2014. In addition, natural-gas prices increased as a result of higher industrial natural-gas demand, reduced natural-gas imports from Canada, and continued strength in exports to Mexico.

2013 vs. 2012 Anadarko's average natural-gas price received increased as higher-than-normal residential and commercial demand early in 2013 reduced overall industry natural-gas storage below the previous year's record levels. Natural-gas prices were further supported by higher demand in the fourth quarter of 2013, a reduction in natural-gas imports from Canada, and continued strength in exports to Mexico.

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Oil and Condensate Sales Volumes, Average Prices, and Revenues

	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
United States					
Sales volumes-MMBbls	**74**	28%	58	6%	55
MBbls/d	**203**	28	158	6	149
Price per barrel	**$ 87.99**	(9)	$ 97.02	-	$ 97.46
International					
Sales volumes-MMBbls	**32**	(1)%	33	7%	31
MBbls/d	**89**	(1)	90	7	84
Price per barrel	**$ 99.79**	(9)	$ 109.15	(2)	$ 111.11
Total					
Sales volumes-MMBbls	**106**	18%	91	6%	86
MBbls/d	**292**	18	248	6	233
Price per barrel	**$ 91.58**	(10)	$ 101.41	(1)	$ 102.35
Oil and condensate sales revenues (millions)	**$ 9,748**	6	$ 9,178	5	$ 8,728

MMBbls-million barrels

Oil and Condensate Sales Volumes

2014 vs. 2013 Anadarko's oil and condensate sales volumes increased by 44 MBbls/d.

- Sales volumes for the Rockies increased by 33 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling.
- Sales volumes for the Southern and Appalachia Region increased by 15 MBbls/d, primarily as a result of increased horizontal drilling and 2013 infrastructure expansion in the Eagleford shale and increased horizontal drilling in the Delaware basin.
- International sales volumes decreased by 1 MBbls/d primarily due to lower sales volumes in China as a result of maintenance downtime and the sale of the Company's Chinese subsidiary and the timing of liftings in Ghana, partially offset by higher sales volumes in Algeria from additional facilities and wells brought online at El Merk.
- Sales volumes in the Gulf of Mexico decreased by 1 MBbls/d primarily due to natural production declines.

2013 vs. 2012 Anadarko's oil and condensate sales volumes increased by 15 MBbls/d.

- Sales volumes for the Rockies increased by 15 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling.
- Sales volumes for the Southern and Appalachia Region increased by 6 MBbls/d, as a result of horizontal drilling and infrastructure expansions in the Eagleford shale.
- International sales volumes increased by 6 MBbls/d primarily in Ghana as a result of enhanced production due to successful acid stimulations and additional Phase 1A Jubilee wells brought online, as well as timing of cargo liftings.
- Sales volumes in the Gulf of Mexico decreased by 10 MBbls/d primarily due to natural production declines.

Oil and Condensate Prices

2014 vs. 2013 Anadarko's average oil price received decreased as a result of a global oversupply and reduced oil demand resulting from continued economic weakness particularly in late 2014.

2013 vs. 2012 Anadarko's average oil price received decreased due to slightly lower international oil prices in 2013.

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Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
United States					
Sales volumes-MMBbls	**43**	28%	33	10%	30
MBbls/d	**116**	28	91	10	83
Price per barrel	**$ 35.48**	(7)	$ 37.97	(6)	$ 40.44
International					
Sales volumes-MMBbls	**1**	NM	-	NM	-
MBbls/d	**3**	NM	-	NM	-
Price per barrel	**$ 56.16**	NM	$ -	NM	$ -
Total					
Sales volumes-MMBbls	**44**	31%	33	10%	30
MBbls/d	**119**	31	91	10	83
Price per barrel	**$ 36.01**	(5)	$ 37.97	(6)	$ 40.44
Natural-gas liquids sales revenues (millions)	**$ 1,572**	25	$ 1,262	3	$ 1,224

NM-not meaningful

NGLs Sales Volumes

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production.

2014 vs. 2013 The Company's NGLs sales volumes increased by 28 MBbls/d.

- Sales volumes in the Rockies increased by 16 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling and the Lancaster plant coming online in April 2014.
- Sales volumes for the Southern and Appalachia Region increased by 10 MBbls/d primarily as a result of increased horizontal drilling and 2013 infrastructure expansion in the Eagleford shale.
- International sales volumes increased by 3 MBbls/d due to the commencement of NGLs sales in 2014 from the Company's El Merk facility in Algeria.

2013 vs. 2012 Anadarko's NGLs sales volumes increased 8 MBbls/d.

- Sales volumes for the Southern and Appalachia Region increased by 12 MBbls/d as a result of increased horizontal drilling and infrastructure expansion in the Eagleford shale and horizontal drilling in the liquids-rich East Texas/North Louisiana horizontal development.
- Sales volumes in the Rockies decreased by 2 MBbls/d primarily due to ethane rejection in 2013.
- Sales volumes in the Gulf of Mexico decreased by 2 MBbls/d due to natural production declines.

NGLs Sales Prices

2014 vs. 2013 Anadarko's average NGLs price received decreased primarily due to lower prices for butanes and natural gasoline resulting from higher industry production levels and related declines in oil prices.

2013 vs. 2012 Anadarko's average NGLs price received decreased primarily due to lower prices for ethane and butanes as a result of higher U.S. inventory and production levels.

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Gathering, Processing, and Marketing Margin

millions except percentages	**2014**	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Gathering, processing, and marketing sales	**$ 1,206**	16%	$ 1,039	14%	$ 911
Gathering, processing, and marketing expense	**1,030**	19	869	14	763
Total gathering, processing, and marketing, net	**$ 176**	4	$ 170	15	$ 148

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko, as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko, as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities.

2014 vs. 2013 Gathering, processing, and marketing, net increased by $6 million primarily due to higher gathering and processing revenue associated with higher volumes, increased natural-gas prices, and increased infrastructure, partially offset by higher processing and transportation expenses due to the increased volumes.

2013 vs. 2012 Gathering, processing, and marketing, net increased by $22 million primarily due to higher gathering revenue as a result of increased volumes and higher marketing margins, partially offset by increased transportation expenses due to increased third-party volumes and increased demand fees.

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Gains (Losses) on Divestitures and Other, net

millions except percentages	**2014**	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Gains (losses) on divestitures	$ **1,891**	NM	$ (470)	NM	$ (71)
Other	**204**	11%	184	5%	175
Total gains (losses) on divestitures and other, net	$ **2,095**	NM	$ (286)	NM	$ 104

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues including minerals sales, earnings from equity investments, and other revenues.

2014

- The Company recognized a gain of $1.5 billion related to its divestiture of a 10% working interest in Offshore Area 1 in Mozambique for sales proceeds of $2.64 billion.
- The Company recognized a gain of $510 million associated with the divestiture of its Chinese subsidiary for sales proceeds of $1.075 billion.
- The Company recognized a gain of $237 million associated with the divestiture of its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for sales proceeds of $500 million.
- The Company recognized gains on divestitures of $127 million for certain oil and gas properties in the United States.
- During the fourth quarter of 2014, Anadarko considered certain U.S. onshore oil and gas assets to be held for sale and recognized a $456 million loss. At December 31, 2014, these assets were no longer considered held for sale as the volatility in the current commodity-price environment reduced the probability that these assets would be sold within the next year.

2013

- The Company recognized losses on assets held for sale of $704 million, primarily associated with the loss of value of the Pinedale/Jonah assets in Wyoming, which were sold in January 2014 for sale proceeds of $581 million.
- The Company divested its interest in a soda ash joint venture for sales proceeds of $310 million, recognizing a gain of $140 million, while retaining its royalty interest in soda ash mined by the joint venture from the Company's Land Grant. Additional consideration may also be received based on future revenue of the joint venture.
- The Company recognized gains on divestitures of $94 million for certain oil and gas properties in the United States.

2012

- The Company recognized losses of $71 million on certain oil and gas properties, primarily related to the sale of oil and gas properties in Indonesia.

See *Note 2-Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on assets held for sale.

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Costs and Expenses

	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Oil and gas operating (millions)	$ **1,171**	7%	$ 1,092	12%	$ 976
Oil and gas operating-per BOE	**3.81**	(1)	3.83	5	3.65
Oil and gas transportation and other (millions)	**1,184**	16	1,022	7	955
Oil and gas transportation and other-per BOE	**3.85**	7	3.59	1	3.57

BOE-barrels of oil equivalent

Oil and Gas Operating Expenses

2014 vs. 2013 Oil and gas operating expense increased by $79 million primarily due to higher costs associated with increased sales volumes in the Rockies and the Southern and Appalachia Region and increased activity in the Gulf of Mexico. These increases were partially offset by lower expenses due to the sales of the Company's Pinedale/Jonah assets and its China subsidiary. The related costs per BOE decreased by $0.02 due to increased sales volumes, partially offset by the higher costs.

2013 vs. 2012 Oil and gas operating expenses increased by $116 million primarily due to increased workovers in the Gulf of Mexico, Rockies, and Southern and Appalachia Region; higher expenses in Algeria associated with the start of El Merk production in 2013; and increased costs associated with increased activity in the Rockies and Southern and Appalachia Region. Oil and gas operating expenses per BOE increased by $0.18 primarily due to these higher costs, partially offset by increased sales volumes.

Oil and Gas Transportation and Other Expenses

2014 vs. 2013 Oil and gas transportation and other expenses increased by $162 million primarily due to higher gas-gathering and transportation costs primarily attributable to higher volumes related to the growth in the Company's U.S. onshore asset base. Oil and gas transportation and other expenses per BOE increased by $0.26 with the higher costs partially offset by increased sales volumes.

2013 vs. 2012 Oil and gas transportation and other expenses increased by $67 million primarily due to higher gas-gathering and transportation costs primarily attributable to higher volumes related to the growth in the Company's U.S. onshore asset base. Oil and gas transportation and other expenses per BOE increased by $0.02, with the higher costs partially offset by increased sales volumes.

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millions		**2014**		2013		2012
Exploration Expense						
Dry hole expense	**$**	**762**	$	556	$	440
Impairments of unproved properties		**483**		308		1,104
Geological and geophysical expense		**168**		208		151
Exploration overhead and other		**226**		257		251
Total exploration expense	**$**	**1,639**	$	1,329	$	1,946

2014 vs. 2013 Exploration expense increased by $310 million.

- Dry hole expense increased by $206 million primarily due to unsuccessful drilling activities expensed in 2014 associated with wells in the Gulf of Mexico, the Rockies, and Mozambique, compared to unsuccessful drilling activities expensed in 2013 associated with wells in Kenya, Sierra Leone, and Côte d'Ivoire.
- Impairments of unproved properties increased by $175 million primarily due to 2014 impairments in the Gulf of Mexico due to lower oil prices, reduction of reserves, and the expiration of certain leases; and impairments in Sierra Leone and certain U.S. onshore oil and gas properties as a result of changes in the Company's drilling plans. Impairments for 2013 included China, Brazil, and a U.S. onshore property as a result of changes in the Company's drilling plans.
- Geological and geophysical expense decreased by $40 million due to lower seismic purchases in the Gulf of Mexico during 2014.

2013 vs. 2012 Exploration expense decreased by $617 million.

- Impairments of unproved properties decreased by $796 million primarily due to 2012 impairments of $721 million related to Powder River coalbed methane properties primarily as a result of lower natural-gas prices and $124 million related to a Gulf of Mexico natural-gas property that the Company did not expect to develop under the forecasted natural-gas price environment.
- Dry hole expense increased by $116 million primarily due to unsuccessful drilling activities expensed in 2013 associated with wells in the Gulf of Mexico, Sierra Leone, Kenya, Côte d'Ivoire, and New Zealand, compared to unsuccessful drilling activities expensed in 2012 associated with wells in Brazil, Sierra Leone, the Gulf of Mexico, Ghana, and Côte d'Ivoire.
- Geological and geophysical expense increased by $57 million primarily due to 2013 seismic purchases in Colombia and the Gulf of Mexico.

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millions except percentages	**2014**	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
General and administrative	**$ 1,316**	21%	$ 1,090	(13)%	$ 1,246
Depreciation, depletion, and amortization	**4,550**	16	3,927	(1)	3,964
Other taxes	**1,244**	16	1,077	(12)	1,224
Impairments	**836**	5	794	104	389

General and Administrative Expenses (G&A)

2014 vs. 2013 G&A expense increased by $226 million primarily due to higher employee-related expenses of $152 million primarily associated with increased headcount and higher bonus plan expense. In addition, G&A expense increased due to higher legal expenses of $38 million primarily related to the third-party reimbursement of legal expenses associated with the Algeria exceptional profits tax settlement received in 2013 and legal fees related to Tronox, as well as higher consulting fees of $15 million.

2013 vs. 2012 G&A expense decreased by $156 million due to reduced legal-related expenses of $101 million and lower employee-related expenses of $60 million. The reduced legal-related expenses primarily related to lower 2013 Tronox legal expenses and the 2013 third-party reimbursement of the Company's legal expenses associated with the Algeria exceptional profits tax settlement. The lower employee-related expenses primarily related to the 2012 expense associated with Unit Appreciation Rights (UARs), partially offset by higher 2013 employee-related expenses associated with operational expansions. The UARs were awarded in prior years to certain officers of the general partner of WES, a consolidated subsidiary of Anadarko, pursuant to the Western Gas Holdings, LLC (WGH) Equity Incentive Plan. This expense related to the change in fair value of the UARs upon the initial public offering (IPO) of WGP.

Depreciation, Depletion, and Amortization (DD&A)

2014 vs. 2013 DD&A expense increased by $623 million primarily due to higher sales volumes in 2014, increased asset retirement costs for wells in the Gulf of Mexico, and increased costs associated with additional gathering and processing facilities.

2013 vs. 2012 DD&A expense decreased by $37 million primarily due to accelerated expense in 2012 associated with the depletion of fields in the Gulf of Mexico, partially offset by higher sales volumes in 2013.

Other Taxes

2014 vs. 2013 Other taxes increased by $167 million.

- Algerian exceptional profits taxes increased by $128 million attributable to higher oil sales volumes and the commencement of NGLs sales in 2014.
- U.S. onshore ad valorem taxes increased by $85 million attributable to increased activity related to U.S. onshore properties.
- Chinese windfall profits tax decreased by $47 million resulting from maintenance downtime in the first half of 2014 and the sale of the Company's Chinese subsidiary in August 2014.

2013 vs. 2012 Other taxes decreased by $147 million.

- Algerian exceptional profits taxes decreased by $116 million due to a lower Algeria effective tax rate resulting from the resolution of the Algeria exceptional profits tax dispute and lower oil prices.
- Lower sales volumes and oil prices resulted in a $33 million decrease in U.S. production and severance taxes primarily in Alaska.

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Impairments

2014

- The Company recognized impairments of $545 million related to certain U.S. onshore oil and gas properties and $276 million related to certain oil and gas properties in the Gulf of Mexico that were impaired primarily due to lower forecasted natural-gas and oil prices.

Declines in commodity prices or negative reserves revisions could result in additional impairments in future periods. See *Note 5-Impairments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on impairments and *Risk Factors* under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGLs prices.

2013

- The Company recognized $562 million due to a reduction in estimated future net cash flows and downward revisions of reserves for certain Gulf of Mexico properties resulting from changes to the Company's development plans.
- The Company recognized $142 million for certain U.S. onshore oil and gas properties and $49 million for related midstream assets due to downward revisions of reserves resulting from changes to the Company's development plans.
- The Company recognized $30 million for certain midstream properties due to a reduction in estimated future cash flows and $11 million related to the Company's Venezuelan cost-method investment due to declines in estimated recoverable value.

2012

- The Company recognized $363 million related to oil and gas exploration and production reporting segment properties located in the United States. These impairments included $259 million related to lower natural-gas prices, $79 million related to downward reserves revisions for a Gulf of Mexico property that was near the end of its economic life, and $25 million for a platform in the Gulf of Mexico.
- The Company recognized impairments of $13 million related to midstream properties and $13 million related to the Company's Venezuelan cost-method investment.

millions	**2014**	2013	2012
Algeria exceptional profits tax settlement	**$ -**	$ 33	$ (1,797)
Deepwater Horizon settlement and related costs	**97**	15	18

Algeria Exceptional Profits Tax Settlement

In March 2012, Anadarko and Sonatrach resolved the exceptional profits tax dispute. The resolution provided for delivery to the Company of oil valued at $1.7 billion and the elimination of $62 million of previously recorded and unpaid transportation charges. The Company recognized a $1.8 billion credit in the Costs and Expenses section of the Consolidated Statement of Income for 2012 to reflect the effect of this agreement for previously recorded expenses. During 2013, the Company revised its estimate of income tax expense related to the elimination of previously recorded and unpaid transportation charges and recognized a $33 million unfavorable adjustment to the settlement, which was offset by an equivalent income tax benefit also recognized in 2013. At December 31, 2013, the Company had collected all of the $1.7 billion associated with the Algeria exceptional profits tax receivable.

Deepwater Horizon Settlement and Related Costs

During 2014, the Company recorded a $90 million expense and contingent liability associated with a civil penalty under the Clean Water Act (CWA) related to the Deepwater Horizon event-related claims. In addition, Deepwater Horizon settlement and related costs included legal expenses and related costs associated with the Deepwater Horizon events for 2014, 2013, and 2012. Refer to *Note 17-Contingencies-Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion and analysis of these events.

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Other (Income) Expense

millions except percentages	**2014**	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Interest Expense					
Current debt, long-term debt, and other	**$ 973**	3%	$ 949	(1)%	$ 963
Capitalized interest	**(201)**	24	(263)	(19)	(221)
Total interest expense	**$ 772**	13	$ 686	(8)	$ 742

2014 vs. 2013 Anadarko's interest expense increased by $86 million primarily due to a decrease in capitalized interest of $62 million related to lower construction-in-progress balances for the Mozambique liquefied natural gas project and the completion of certain U.S. pipeline projects in late 2013 and early 2014. In addition, interest expense increased $13 million due to increased long-term debt outstanding during 2014. For additional information, see *Liquidity and Capital Resources* and *Interest-Rate Risk* under Item 7A of this Form 10-K.

2013 vs. 2012 Anadarko's interest expense decreased by $56 million primarily due to an increase in capitalized interest of $42 million related to higher construction-in-progress balances for long-term capital projects. Additionally, interest expense decreased by $31 million as a result of the repayment of outstanding borrowings during 2012 associated with the $5.0 billion Facility. These decreases were partially offset by $18 million of interest expense for outstanding borrowings primarily related to WES's 4.000% Senior Notes due 2022, which were issued during 2012.

millions	**2014**	2013	2012
(Gains) Losses on Derivatives, net			
(Gains) losses on commodity derivatives, net	**$ (589)**	$ 141	$ (387)
(Gains) losses on interest-rate and other derivatives, net	**786**	(539)	61
Total (gains) losses on derivatives, net	**$ 197**	$ (398)	$ (326)

(Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments as a result of changes in commodity prices and interest rates. Anadarko enters into commodity derivatives to manage the risk of changes in the market prices for its anticipated sales of production. In addition, Anadarko enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to interest-rate changes. For additional information, see *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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millions except percentages		**2014**	Inc/(Dec) vs. 2013		2013	Inc/(Dec) vs. 2012		2012
Other (Income) Expense, net								
Interest income	$	**(26)**	37%	$	(19)	19%	$	(16)
Other		**46**	57		108	NM		12
Total other (income) expense, net	**$**	**20**	78	$	89	NM	$	(4)

2014 vs. 2013 In 2013, as a result of a Chapter 11 bankruptcy declaration by a third party, the U.S. Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, which were previously sold to the third party. During 2013, the Company accrued costs of $117 million to decommission the facility and related wells. During 2014, the Company recognized a $22 million increase in the estimated decommissioning costs. Anadarko completed decommissioning of the production facility in 2014 and expects to complete decommissioning of the wells in 2015. Also, as a result of a prior acquisition, the Company recognized a restoration liability of $50 million in 2013 with respect to a landfill located in California for which the Company was notified that it is a potentially responsible party. In the second quarter of 2013, the Company reversed the $56 million tax indemnification liability associated with the 2006 sale of the Company's Canadian subsidiary. The indemnity was reversed as a result of certain changes to Canadian tax laws.

2013 vs. 2012 During 2013, the Company recognized a decommissioning charge of $117 million and a restoration liability of $50 million, partially offset by the 2013 reversal of the $56 million tax indemnification liability associated with the 2006 sale of the Company's Canadian subsidiary.

millions		**2014**		2013		2012
Tronox-related contingent loss	**$**	**4,360**	$	850	$	(250)

In April 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) entered into a settlement agreement for $5.15 billion resolving all claims asserted in the Tronox Adversary Proceeding. Anadarko recognized Tronox-related contingent losses of $4.3 billion in 2014, $850 million in 2013, and reversed $250 million in 2012 associated with the Tronox-related contingent loss recognized in 2011. In addition, Anadarko recognized settlement-related interest expense of $60 million during 2014. An aggregate Tronox-related contingent liability of $5.2 billion was included on the Company's Consolidated Balance Sheet at December 31, 2014. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective. See *Note 17-Contingencies-Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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Income Tax Expense

millions except percentages	**2014**	2013	2012
Income tax expense (benefit)	$ **1,617**	$ 1,165	$ 1,120
Effective tax rate	**2,994%**	55%	31%

2014 The increase from the 35% U.S. federal statutory rate was primarily attributable to net changes in uncertain tax positions related to the settlement agreement associated with the Tronox Adversary Proceeding, changes in other uncertain tax positions, the tax impact from foreign operations, Algerian exceptional profits taxes, and the non-deductible contingent CWA-penalty accrual. For additional information on income tax rates, see *Note 18-Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In 2013, the Company recognized a deferred tax benefit of $274 million related to the $850 million loss with respect to the Tronox-related contingent liability. In 2014, the Company recognized an additional deferred tax benefit of $316 million related to the additional $4.360 billion loss with respect to the Tronox-related contingent liability. See *Note 17-Contingencies-Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

2013 The increase from the 35% U.S. federal statutory rate was primarily attributable to the tax impact from foreign operations, non-deductible Algerian exceptional profits tax, and deferred tax adjustments.

2012 The decrease from the 35% U.S. federal statutory rate was primarily attributable to the non-taxable resolution of the Algeria exceptional profits tax dispute. This amount was partially offset by the tax impact from foreign operations and non-deductible Algerian exceptional profits tax.

Net Income Attributable to Noncontrolling Interests

The Company's net income attributable to noncontrolling interests of $187 million for the year ended December 31, 2014, $140 million for 2013, and $54 million for 2012, was related to public ownership interests in WES and WGP. Public ownership of WES was 55% at December 31, 2014, 56.4% at December 31, 2013, and 51.8% at December 31, 2012. In December 2012, WGP completed its IPO of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit. During 2014, Anadarko sold approximately 6 million WGP common units to the public, raising net proceeds of $335 million. Public ownership of WGP was 11.7% at December 31, 2014, and was 9% at December 31, 2013 and 2012. See *Note 9-Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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OPERATING RESULTS

Segment Analysis-Adjusted EBITDAX To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Algeria exceptional profits tax settlement, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX, which is not a GAAP measure, excludes exploration expense as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures prepared in accordance with GAAP, such as operating income or cash flows from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect net income (loss) attributable to common stockholders and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Anadarko's results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes, and consolidated Adjusted EBITDAX by reporting segment.

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Adjusted EBITDAX

millions except percentages	2014	Inc/(Dec) vs. 2013	2013	Inc/(Dec) vs. 2012	2012
Income (loss) before income taxes	**$ 54**	(97)%	$ 2,106	(41)%	$ 3,565
Exploration expense	**1,639**	23	1,329	(32)	1,946
DD&A	**4,550**	16	3,927	(1)	3,964
Impairments	**836**	5	794	104	389
Interest expense	**772**	13	686	(8)	742
Total (gains) losses on derivatives, net, less net cash received in settlement of commodity derivatives	**578**	NM	(307)	(169)	443
Deepwater Horizon settlement and related costs	**97**	NM	15	(17)	18
Algeria exceptional profits tax settlement	**-**	(100)	33	102	(1,797)
Tronox-related contingent loss	**4,360**	NM	850	NM	(250)
Certain other nonoperating items	**22**	(80)	110	NM	-
Less net income attributable to noncontrolling interests	**187**	34	140	159	54
Consolidated Adjusted EBITDAX	**$ 12,721**	35	$ 9,403	5	$ 8,966
Adjusted EBITDAX by segment					
Oil and gas exploration and production	**$ 12,505**	35	$ 9,238	9	$ 8,500
Midstream	**660**	30	508	7	474
Marketing	**(219)**	(75)	(125)	(20)	(104)
Other and intersegment eliminations	**(225)**	(3)	(218)	NM	96

Oil and Gas Exploration and Production

2014 vs. 2013 The increase in Adjusted EBITDAX was primarily due to net gains on divestitures, higher sales volumes for oil and NGLs, and higher natural-gas prices. These increases were partially offset by lower oil prices, and higher oil and gas transportation expenses and other taxes, which increased as a result of higher sales volumes.

2013 vs. 2012 The increase in Adjusted EBITDAX was primarily due to higher sales volumes for all products and higher natural-gas prices, partially offset by lower oil and NGLs prices and losses on divestitures primarily related to the Pinedale/Jonah assets in Wyoming.

Midstream

2014 vs. 2013 The increase in Adjusted EBITDAX was primarily due to higher gathering and processing revenue associated with higher volumes and increased natural-gas prices, partially offset by higher processing expenses primarily due to increased volumes.

2013 vs. 2012 The increase in Adjusted EBITDAX was primarily due to higher gathering revenue as a result of increased volumes.

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Marketing

2014 vs. 2013 The decrease in Adjusted EBITDAX resulted from lower marketing margins and higher transportation expenses.

2013 vs. 2012 The decrease in Adjusted EBITDAX resulted from higher transportation expenses due to increased third-party volumes and increased demand fees, partially offset by higher margins primarily associated with natural-gas and NGLs sales.

Other and Intersegment Eliminations

Other and intersegment eliminations consists primarily of corporate costs, income from hard minerals investments and royalties, and net cash received in settlement of commodity derivatives.

2014 vs. 2013 The Adjusted EBITDAX in 2014 was relatively flat compared to the prior year.

2013 vs. 2012 The increase in Adjusted EBITDAX was primarily due to a decrease in net cash received in settlement of commodity derivatives in 2013, partially offset by 2012 expense associated with the change in the fair value of the general partner UARs in connection with the WGP IPO. The UARs were awarded in prior years to certain officers of the general partner of WES, pursuant to the WGH Equity Incentive Plan.

Proved Reserves Anadarko is focused on growth and profitability, and reserves replacement is a key to growth. Future profitability partially depends on commodity prices and the cost of finding and developing oil and gas reserves. Reserves growth can be achieved through successful exploration and development drilling, improved recovery, or acquisition of producing properties. For reserves information, see *Oil and Gas Properties and Activities-Proved Reserves* under Items 1 and 2 of this Form 10-K and the *Supplemental Information on Oil and Gas Exploration and Production Activities* under Item 8 of this Form 10-K.

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LIQUIDITY AND CAPITAL RESOURCES

Overview Anadarko generates cash needed to fund capital expenditures, debt-service obligations, and dividend payments primarily from operating activities, and enters into debt and equity transactions to maintain its desired capital structure and to finance acquisition opportunities. The Company has a variety of funding sources available, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, commercial paper, and the Company's New Credit Facilities. In addition, as of January 2014, an effective registration statement is available to Anadarko covering the sale of up to 40 million WGP common units. These common units were issued to Anadarko in connection with WGP's IPO in December 2012. During 2014, the Company sold 6 million WGP common units and at December 31, 2014, the Company had 34 million units available for sale.

During 2014, the primary source for funding of capital investments was cash flows from operating activities. The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions.

At December 31, 2014, Anadarko had no scheduled debt maturities during the next year. Anadarko's Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $796 million at the next put date in October 2015. The Zero Coupons are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt. See *Note 12-Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on the Zero Coupons. Anadarko's scheduled 2016 debt maturities are $1.8 billion, exclusive of the Zero Coupons.

Management believes that the Company's liquidity position, asset portfolio, and operating and financial performance provide the necessary financial flexibility to fund the Company's current and long-term operations.

Tronox Adversary Proceeding Settlement Payment In April 2014, Anadarko and Kerr-McGee entered into a settlement agreement to resolve all claims asserted in the Tronox Adversary Proceeding for $5.15 billion. In addition, the Company agreed to pay interest on the above amount from April 3, 2014, through the payment of the settlement, with an annual interest rate of 1.5% for the first 180 days and 1.5% plus the one-month LIBOR thereafter. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective. See *Note 17-Contingencies-Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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Revolving Credit Facilities and Commercial Paper Program During 2014, the Company maintained the $5.0 billion Facility maturing in September 2015. Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko has to lenders or their affiliates pursuant to certain derivative instruments as discussed in *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, were guaranteed by certain of the Company's wholly owned domestic subsidiaries, and were secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries. During 2014, the Company had no outstanding borrowings under the $5.0 billion Facility.

In June 2014, Anadarko entered into a $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility), which is expandable to $4.0 billion, and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). The New Credit Facilities replaced the $5.0 billion Facility upon satisfaction of certain conditions, including the January 2015 settlement payment related to the Tronox Adversary Proceeding. Under the New Credit Facilities, the Company's derivative counterparties no longer maintain security interests in any of the Company's assets. As a result, the Company may be required from time to time to post collateral of cash or letters of credit based on the negotiated terms of the individual derivative agreements.

In January 2015, the Company borrowed $1.5 billion under the 364-Day Facility. Borrowings under the New Credit Facilities generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

In January 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes.

Financial Covenants The $5.0 billion Facility contained various customary covenants with which Anadarko had to comply, including, but not limited to, limitations on incurrence of indebtedness, liens on assets, and asset sales. Anadarko was also required to maintain, at the end of each quarter, (i) a Consolidated Leverage Ratio of no more than 4.5 to 1.0 (relative to Consolidated EBITDAX for the most recent period of four calendar quarters), (ii) a ratio of Current Assets to Current Liabilities of no less than 1.0 to 1.0, and (iii) a Collateral Coverage Ratio of no less than 1.75 to 1.0, in each case, as defined in the $5.0 billion Facility. The Collateral Coverage Ratio was the ratio of an annually redetermined value of pledged assets to outstanding loans under the $5.0 billion Facility. Additionally, to borrow from the $5.0 billion Facility, the Collateral Coverage Ratio had to be no less than 1.75 to 1.0 after giving pro forma effect to the requested borrowing.

The covenants contained in certain of the Company's credit agreements provide for a maximum Anadarko debt-to-capitalization ratio of 67%. The covenants do not specifically restrict the payment of dividends; however, the impact of dividends paid on the Company's debt-to-capitalization ratio must be considered to ensure covenant compliance. At December 31, 2014, Anadarko was in compliance with all financial covenants.

The New Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65%, and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes.

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WES Funding Sources Anadarko's consolidated subsidiary, WES, uses cash flows from operations to fund ongoing operations (including capital investments in the ordinary course of business), service its debt, and make distributions to its equity holders. As needed, WES supplements cash generated from its operating activities with proceeds from debt or equity issuances or borrowings under its five-year $1.2 billion senior unsecured revolving credit facility (RCF).

In February 2014, WES entered into the RCF, which amended and restated its then-existing $800 million senior unsecured revolving credit facility. The RCF matures in February 2019 and is expandable to a maximum of $1.5 billion. Borrowings under the RCF bear interest at (i) LIBOR plus an applicable margin ranging from 0.975% to 1.45%, depending on WES's credit rating, or (ii) the greatest of (a) the Wells Fargo Bank, National Association prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus, in each case, an applicable margin ranging from 0.00% to 0.45%. At December 31, 2014, WES was in compliance with all covenants contained in its RCF, had outstanding borrowings under its RCF of $510 million at an interest rate of 1.47%, and had available borrowing capacity of approximately $677 million ($1.2 billion capacity, less $510 million of outstanding borrowings and $13 million of outstanding letters of credit).

In August 2014, WES filed a registration statement with the Securities and Exchange Commission authorizing the issuance of up to an aggregate of $500 million of common units, in amounts, at prices, and on terms to be determined by market conditions and other factors at the time of the offerings.

Insurance Coverage and Other Indemnities Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage includes (a) $400 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, redrill, and sudden and accidental pollution; (b) $700 million per occurrence from the commercial markets for the items described in item (a) above, which is in excess of the OIL coverage and which follows the form of OIL coverage with certain exceptions; (c) $400 million from the commercial markets, which scales to Anadarko's working interest, for third-party liabilities including sudden and accidental pollution and aviation liability; and (d) $275 million for aircraft liability (in addition to the third-party liability limits described in item (c) above). Anadarko does not carry significant coverage for loss of production income from any of the Company's facilities or for any losses that result from the effects of a named windstorm.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

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Following is a discussion of significant sources and uses of cash flows for the three-year period ended December 31, 2014. Forward-looking information related to the Company's liquidity and capital resources is discussed in *Outlook* that follows.

Sources of Cash

Operating Activities Anadarko's cash flows from operating activities in 2014 was $8.5 billion compared to $8.9 billion in 2013 and $8.3 billion in 2012. Cash flows from operating activities for 2014 decreased year over year due to $730 million of cash received in 2013 associated with the Algeria exceptional profits tax settlement, a $520 million income tax payment in 2014 associated with the Company's divestiture of a 10% working interest in Offshore Area 1 in Mozambique, lower average oil and NGLs prices, lower natural-gas volumes, higher operating expenses, and the unfavorable impact of changes in working capital items. These decreases were substantially offset by higher average natural-gas prices, higher sales volumes for oil and NGLs, and net cash received in settlement of commodity derivative instruments. Cash flows from operating activities for 2013 increased year over year primarily due to higher sales volumes, higher average natural-gas prices, and the favorable impact of changes in working capital items. These increases were partially offset by lower average oil and NGLs prices and a decrease in cash collected in 2013 associated with the Algeria exceptional profits tax receivable.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuation in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales-volume changes also impact cash flow, but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to continued operations and debt service.

Investing Activities Anadarko received pretax sales proceeds related to property divestiture transactions of $5.0 billion in 2014, $567 million in 2013, and $657 million in 2012. The increase in 2014 was primarily related to the Company's divestitures of a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion, its Chinese subsidiary for $1.075 billion, its interest in the Pinedale/Jonah assets in Wyoming for $581 million, and its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for $500 million.

Financing Activities During 2014, Anadarko's consolidated subsidiary, WES, borrowed $1.2 billion under its RCF primarily to partially fund its acquisitions of DBM and Anadarko's interests in Texas Express Pipeline LLC, Texas Express Gathering LLC, and Front Range Pipeline LLC and for other general partnership purposes, including the funding of capital expenditures. During 2014, WES completed public offerings of $100 million aggregate principal amount of 2.600% Senior Notes due 2018 and $400 million aggregate principal amount of 5.450% Senior Notes due 2044. These proceeds were used to repay borrowings under WES's RCF and for general partnership purposes. During 2014, WES issued approximately 10 million common units to the public, raising total net proceeds of $691 million. The proceeds were used to partially fund a portion of its DBM acquisition. WES used all the capacity to issue units under the $125 million continuous offering program as of the end of the third quarter of 2014.

During 2014, Anadarko sold approximately 6 million WGP common units to the public, raising net proceeds of $335 million. Also, during 2014, Anadarko completed public offerings of $625 million aggregate principal amount of 3.450% Senior Notes due 2024 and $625 million aggregate principal amount of 4.500% Senior Notes due 2044. These proceeds were used for general corporate purposes.

During 2013, WES borrowed $710 million under its RCF, primarily to fund the 2013 acquisitions of an interest in certain gas-gathering systems located in the Marcellus shale in north-central Pennsylvania and an intrastate pipeline in southwestern Wyoming, and for other general partnership purposes, including the funding of capital expenditures. During 2013, WES also issued approximately 12 million common units to the public, including the $125 million continuous offering program. These offerings raised net proceeds of $725 million, which were primarily used to repay outstanding RCF borrowings and for other general partnership purposes, including funding of WES's capital expenditures. Also in 2013, WES completed a public offering of $250 million aggregate principal amount of 2.600% Senior Notes due 2018, with net proceeds from the offering used to repay outstanding borrowings under its RCF.

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During 2012, WES borrowed $374 million under its RCF, primarily to fund the acquisition of certain midstream assets from Anadarko. Also during 2012, WES completed a public offering of $670 million aggregate principal amount of 4.000% Senior Notes due 2022 and issued five million common units to the public, raising net proceeds of $212 million. Proceeds from these public offerings were used to repay outstanding RCF borrowings and for other general partnership purposes, including the funding of capital expenditures.

In December 2012, WGP completed its IPO of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit, for net proceeds of $411 million. The proceeds were used by WGP to purchase common and general partner units in WES, and were in turn used by WES for general partnership purposes, including the funding of WES capital expenditures.

Uses of Cash

Anadarko invests significant capital to develop, acquire, and explore for oil and natural-gas resources and to expand its midstream infrastructure. The Company also uses cash to fund ongoing operating costs, capital contributions to equity investments, debt repayments, and distributions to its shareholders.

Capital Expenditures The following presents the Company's capital expenditures by category:

millions	**2014**	2013	2012
Property acquisitions			
Exploration	$ **283**	$ 327	$ 239
Development	**3**	324	-
Exploration	**1,711**	1,970	2,064
Development	**6,715**	4,865	4,064
Total oil and gas costs incurred (1)	**8,712**	7,486	6,367
Less corporate acquisitions and non-cash property transactions	**(1)**	6	32
Less asset retirement costs	**347**	180	98
ess geological and geophysical, exploration overhead, delay rentals expenses, and other expenses	**543**	430	401
Total oil and gas capital expenditures	**7,823**	6,870	5,836
Gathering, processing, and marketing and other (2)	**1,433**	1,653	1,475
Total capital expenditures (1)	$ **9,256**	$ 8,523	$ 7,311

(1) Oil and gas costs incurred represent costs related to finding and developing oil and gas reserves. Costs associated with activities of the Company's midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included in oil and gas costs incurred. Capital expenditures represent additions to property and equipment excluding corporate acquisitions and non-cash property transactions and asset retirement costs. Capital expenditures and costs incurred are presented on an accrual basis. Additions to properties and equipment and dry hole costs on the Consolidated Statements of Cash Flows include certain adjustments that give effect to the timing of actual cash payments to provide a cash-basis presentation.

(2) Includes WES capital expenditures of $696 million in 2014, $792 million in 2013, and $529 million in 2012.

The Company's capital expenditures increased by 9% for the year ended December 31, 2014, due to increased development drilling primarily in the Wattenberg field of $663 million and in the Eagleford shale of $546 million and to a spar lease buyout of $110 million in the Gulf of Mexico. The increase in the Eagleford shale was primarily due to the 2013 development drilling being funded by a third party as a result of a carried-interest agreement that was fully funded in June 2013. These 2014 increases were partially offset by 2013 acquisitions of certain oil and gas properties and related assets in the Moxa area of Wyoming for $310 million, primarily representing the fair value of the oil and gas properties acquired, and the acquisition of a 33.75% interest in gas-gathering systems located in the Marcellus shale in north-central Pennsylvania from a third party by WES for $135 million.

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In the third quarter of 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2016. At December 31, 2014, $22 million of the total $442 million obligation had been funded.

The Company's capital spending increased by 17% for the year ended December 31, 2013, due to development drilling onshore and offshore in the United States and acquisitions of oil and gas development properties and domestic onshore plants and gathering systems. In 2013, Anadarko exchanged certain oil and gas properties in the Wattenberg field with a third party to enhance the Company's core acreage position, in which $106 million of capital was incurred. Also in 2013, Anadarko acquired certain oil and gas properties and related assets in the Moxa area of Wyoming for $310 million, primarily representing the fair value of the oil and gas properties acquired. In 2013, WES acquired a 33.75% interest in gas-gathering systems for $135 million and an intrastate pipeline in southwestern Wyoming for $28 million. These increases were offset by lower capital spending associated with decreased exploration drilling in West Africa and U.S. onshore and lower capital requirements to Anadarko related to development projects as a result of the carried-interest arrangements discussed below.

In 2013, the Company entered into a carried-interest arrangement that requires a third party to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. The third-party funding is expected to cover the substantial majority of Anadarko's expected future capital costs through first production, which is expected to occur by mid-2016. At December 31, 2014, $386 million of the total $860 million obligation had been funded.

In the third quarter of 2012, the Company entered into a carried-interest arrangement that required a third party to fund $556 million of Anadarko's capital costs in exchange for a 7.2% working interest in the Lucius development, located in the Gulf of Mexico. During the second quarter of 2014, as dictated by the Unitization and Participation Agreement, the working interests of all partners in the Lucius development were recalculated. As a result, Anadarko's working interest in the Lucius development was reduced from 27.8% to 23.8% and its capital expenditures were reduced by $44 million due to the re-determination. In addition, the working interest of the third party that participated in the carried-interest arrangement was reduced from 7.2% to 6.2%, which resulted in a reduction in the funding commitment from $556 million to $476 million. The funding commitment, which was fully funded during the second quarter of 2014, covered the substantial majority of the Company's capital costs through first production, which occurred in the fourth quarter of 2014.

Pension Contributions During 2014, the Company made contributions of $106 million to its funded pension plans, $15 million to its unfunded pension plans, and $15 million to its unfunded other postretirement benefit plans, which are included in Operating Activities in the Consolidated Statement of Cash Flows. Contributions to the funded pension plans decreased in 2014 as a result of favorable asset returns in 2013. Contributions made to the unfunded pension plans in 2014 were lower as a result of higher funding in 2013 related to the retirement of the Company's former Chief Executive Officer. The Company expects to contribute $5 million to its funded pension plans, $24 million to its unfunded pension plans, and $16 million to its unfunded other postretirement benefit plans in 2015.

During 2013, the Company made contributions of $123 million to its funded pension plans, $37 million to its unfunded pension plans, and $14 million to its unfunded other postretirement benefit plans. The increase in contributions to the funded pension plans in 2013 resulted from a decrease in the discount rates used for funding purposes.

During 2012, the Company made contributions of $101 million to its funded pension plans, $6 million to its unfunded pension plans, and $19 million to its unfunded other postretirement benefit plans. The decrease in contributions to the funded pension plans in 2012 resulted from an increase in the discount rates used for funding purposes.

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Investments During 2014, the Company made capital contributions of $167 million related to equity investments, which are included in Other-net under Investing Activities in the Consolidated Statement of Cash Flows. These contributions were primarily associated with joint ventures for a gas processing plant, marine well containment, and pipelines. The Company made capital contributions related to equity investments of $396 million in 2013, which were primarily associated with joint ventures to build the Front Range Pipeline, the Texas Express Pipeline, and two fractionation trains in Mont Belvieu. The Company made capital contributions related to equity investments of $205 million in 2012.

Debt Retirements and Repayments During 2014, Anadarko repaid $775 million of Senior Notes that matured during 2014. Also, WES repaid $650 million of borrowings under its RCF with proceeds from debt and equity offerings, as discussed in *Sources of Cash.* During 2013, WES repaid $710 million of borrowings under its RCF with proceeds from debt and equity offerings. During 2012, the Company repaid the entire $2.5 billion of borrowings under its $5.0 billion Facility, and retired $131 million of 6.125% Senior Notes that matured in March 2012 and $39 million of 5.000% Senior Notes that matured in October 2012. In addition, WES repaid $374 million of borrowings under its RCF.

For additional information on the Company's debt instruments, such as transactions during the period, years of maturity, and interest rates, see *Note 12-Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends and Distributions to Noncontrolling Interest Owners Anadarko paid dividends to its common stockholders of $505 million in 2014, $274 million in 2013, and $181 million in 2012. The Company increased the quarterly dividend paid to common stockholders from $0.09 per share to $0.18 per share during the third quarter of 2013. During the second quarter of 2014, Anadarko increased the quarterly dividend paid to common stockholders from $0.18 per share to $0.27 per share. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986. The amount of future dividends paid to Anadarko common stockholders will be determined by the Board of Directors on a quarterly basis and will depend on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors.

WES distributed to its unitholders, other than Anadarko, an aggregate of $175 million in 2014, $130 million in 2013, and $100 million in 2012. WES has made quarterly distributions to its unitholders since its IPO in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.70 per common unit for the fourth quarter of 2014 (paid in February 2015).

WGP distributed to its unitholders, other than Anadarko, an aggregate of $24 million during 2014 and $12 million in 2013. WGP declared a cash distribution of $0.31250 per unit for the fourth quarter of 2014 (to be paid in February 2015).

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Outlook

Oil, natural-gas, and NGLs prices can have significant price fluctuations. The Company's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on the prices the Company receives for oil, natural gas, and NGLs. During 2014, New York Mercantile Exchange West Texas Intermediate oil prices ranged from a high of $107.26 per barrel to a low of $53.27 per barrel at the end of 2014. The duration and magnitude of the decline in oil prices cannot be predicted.

The Company has a deep portfolio of investment opportunities and the financial strength and operational flexibility to move capital spending from areas focused on near-term production growth to areas focused on longer-term growth where anticipated returns are less sensitive to spot oil and natural-gas prices. The recent decline in oil prices may result in the Company significantly reducing its capital expenditures in 2015 versus 2014. The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans as prices fluctuate while maintaining the appropriate liquidity and financial flexibility.

The Company is committed to the execution of its worldwide exploration, appraisal, and development programs. The Company currently plans to allocate approximately 65% of its 2015 capital spending to development activities, 15% to exploration activities, and 20% to gas-gathering and processing activities and other business activities. The Company currently expects its 2015 capital spending by area to be approximately 55% for the U.S. onshore region and Alaska, 10% for the Gulf of Mexico, 20% for Midstream and other, and 15% for International.

Anadarko believes that its cash on hand, available borrowing capacity, and expected level of operating cash flows will be sufficient to fund the Company's projected operational and capital programs for 2015 and continue to meet its other current obligations. The Company's cash on hand is available for use and could be supplemented, as needed, with available borrowing capacity under the New Credit Facilities and the commercial paper program. The Company may also enter into carried-interest arrangements with third parties to fund certain capital expenditures, execute asset divestitures, and sell a portion of the WGP common units that it owns in order to supplement cash flow.

The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions. To reduce commodity-price risk and increase the predictability of 2015 cash flows, Anadarko entered into strategic derivative positions, which cover a portion of its anticipated natural-gas sales volumes for 2015. For details of derivative positions at December 31, 2014, see *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Off-Balance-Sheet Arrangements

Anadarko may enter into off-balance-sheet arrangements and transactions that can give rise to material off-balance-sheet obligations. The Company's material off-balance-sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing, treating, transportation, and storage of natural gas, oil, and NGLs, as well as for other oil and gas activities as discussed below in *Obligations and Commitments*. Other than the items discussed above, there are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of or requirements for capital resources.

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Obligations and Commitments

The following is a summary of the Company's obligations at December 31, 2014:

	Obligations by Period (1)				
millions	**2015**	**2016-2017**	**2018-2019**	**2020 and beyond**	**Total**
Total debt					
Principal-long-term borrowings (2)	$ -	$ 3,750	$ 1,874	$ 11,063	$ 16,687
Principal-capital lease obligation	-	-	1	20	21
Investee entities' debt (3)	-	-	-	2,853	2,853
Interest on borrowings	876	1,647	1,219	7,907	11,649
Interest on capital lease obligations	2	3	3	15	23
Investee entities' interest (3)	41	152	199	2,574	2,966
Operating leases					
Drilling rig commitments	939	1,310	460	28	2,737
Production platforms	33	43	43	51	170
Other	50	72	24	8	154
Asset retirement obligations	258	413	180	1,202	2,053
Midstream and marketing activities	930	1,904	1,775	2,656	7,265
Oil and gas activities	1,295	1,059	426	400	3,180
Derivative liabilities (4)	43	1,200	-	-	1,243
Uncertain tax positions, interest, and penalties (5)	123	193	5	11	332
Environmental liabilities	20	19	9	78	126
Other	40	222	-	-	262
Total	$ 4,650	$ 11,987	$ 6,218	$ 28,866	$ 51,721

(1) This table does not include the Tronox-related contingent liability, other litigation-related contingent liabilities, or the Company's pension and postretirement benefit obligations. See *Note 17-Contingencies-Tronox Litigation* and *Note 21-Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) Includes the fully accreted principal amount of the Zero Coupons of approximately $2.4 billion as coming due after 2019. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October, in whole or in part, for the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $796 million in October 2015 (the next potential put date).

(3) Anadarko has legal right of setoff and intends to net-settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Consolidated Balance Sheets in other long-term liabilities-other for all periods presented. These notes payable provide for a variable rate of interest, reset quarterly. Therefore, future interest payments presented in the table above are estimated using the forward LIBOR rate curve. Further, the above table does not reflect the preferred return that Anadarko receives on its investment in these entities, which is also LIBOR-based, but with a lower margin than the margin on the associated notes payable. See *Note 10-Equity-Method Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(4) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties. See *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(5) See *Note 18-Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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Operating Leases Operating lease obligations include approximately $2.5 billion related to seven offshore drilling vessels and $208 million related to certain contracts for U.S. onshore drilling rigs. Anadarko manages its access to rigs to support the execution of its drilling strategy over the next several years. Lease payments associated with the drilling of exploratory wells and development wells, net of amounts billed to partners, will initially be capitalized as a component of oil and gas properties, and either depreciated or impaired in future periods or written off as exploration expense. At December 31, 2014, the Company had $324 million in various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. For additional information, see *Note 16-Commitments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Asset Retirement Obligations Anadarko is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of Anadarko's asset retirement obligations (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. The Company's AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Midstream and Marketing Activities Anadarko has entered into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its natural gas, oil, and NGLs in certain areas.

Oil and Gas Activities At December 31, 2014, Anadarko had various long-term contractual commitments pertaining to exploration, development, and production activities that extend beyond 2014. The Company has work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, and fulfilling rig commitments. The preceding table includes long-term drilling and work-related commitments of $3.2 billion, comprised of approximately $2.0 billion related to the United States and $1.2 billion related to international locations.

Environmental Liabilities Anadarko is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. At December 31, 2014, the Company's Consolidated Balance Sheet included a $126 million liability for remediation and reclamation obligations. The Company continually monitors the liability recorded and ongoing remediation and reclamation activities, and believes the amount recorded is appropriate. For additional information on environmental issues, see *Risk Factors* under Item 1A of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP in the United States requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. See *Note 1-Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's significant accounting policies. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection, development, and disclosure of these estimates is discussed with the Company's Audit Committee.

Proved Reserves

Anadarko estimates its proved oil and gas reserves according to the definition of proved reserves provided by the Securities and Exchange Commission and the Financial Accounting Standards Board (FASB). This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based on expected future conditions.

The Company's estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions, as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date.

The quantities of estimated proved oil and gas reserves are a significant component of DD&A. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments. If the estimates of proved reserves used in the unit-of-production calculations had been lower by five percent across all calculations, DD&A in 2014 would have increased by approximately $210 million.

Exploratory Costs

Under the successful efforts method of accounting, exploratory costs associated with a well discovering hydrocarbons are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in future periods. See *Note 6-Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

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Fair Value

The Company estimates fair value for long-lived assets for impairment testing, reporting units for goodwill impairment testing when necessary, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, pension plan assets, and initial measurements of AROs. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost, income, or market valuation approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management's best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions, such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, future net cash flows, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors, and are consistent with assumptions used in the Company's business plans and investment decisions.

Property Impairments

When circumstances indicate that proved oil and gas properties may be impaired, the expected undiscounted future net cash flows of the asset group are compared to the carrying amount of the asset. If the expected undiscounted future net cash flows, based on our estimate of future oil and natural-gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the carrying amount, the carrying amount is reduced to fair value. Fair value estimates require significant judgment and oil and natural-gas prices are a significant component of the fair-value estimate. Prices have exhibited significant volatility in the past, and the Company expects that volatility to continue in the future.

A long-lived asset other than unproved oil and gas property is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its undiscounted future net cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value. The Company uses a variety of fair-value measurement techniques as discussed below when market information for the same or similar assets does not exist.

Goodwill Impairments

The Company tests goodwill for impairment annually at October 1, or more frequently as circumstances dictate. The first step in assessing whether an impairment of goodwill is necessary is an optional qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is greater than its carrying amount. If the Company concludes that fair value of the reporting unit more than likely exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment is not performed or indicates fair value of the reporting unit may be less than its carrying amount, the Company compares the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determines whether impairment is necessary.

Because quoted market prices for the Company's reporting units are not available, management applies judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management uses all available information to make these fair-value estimates, including the present values of expected future cash flows using discount rates commensurate with the risks associated with the assets and observable for the oil and gas exploration and production reporting unit, control premiums and market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA) for the gathering and processing and transportation reporting units.

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In estimating the fair value of its oil and gas exploration and production reporting unit, the Company assumes production profiles used in its estimation of reserves that are disclosed in the Company's supplemental oil and gas disclosures, market prices based on the forward price curve for oil and gas at the test date (adjusted for location and quality differentials), capital and operating costs consistent with pricing and expected inflation rates, and discount rates that management believes a market participant would use based upon the risks inherent in Anadarko's operations. Management also includes control premium assumptions based on observable market information regarding how a market participant would value the oil and gas exploration and reporting unit as a whole rather than as individual properties that are part of an oil and gas portfolio.

For the Company's other gathering and processing, WES gathering and processing, and WES transportation reporting units, the Company estimates fair value by applying an estimated multiple to projected EBITDA. The Company considered observable transactions in the market and trading multiples for peers in determining an appropriate multiple to apply against the Company's projected EBITDA for these reporting units.

A lower fair-value estimate in the future for any of these reporting units could result in impairment of goodwill. Factors that could trigger a lower fair-value estimate include commodity-price declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets, as well as difficulty or potential delays in obtaining drilling permits or other unanticipated events.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates when it establishes liabilities for environmental remediation, litigation, and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to the Company. The extent of information available varies based on the status of the litigation and the Company's evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change the Company's estimate of litigation-related liabilities including discovery activities, briefings filed with the relevant court, rulings from the court in the process or at the conclusion of any trial, and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, the Company evaluates the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures that could arise related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel and environmental personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of the Company's liability for these contingencies.

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Income Taxes

The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax-credit carryforwards. The Company routinely assesses the realizability of its deferred tax assets by analyzing the reversal periods of available net operating loss carryforwards and credit carryforwards, temporary differences in tax assets and liabilities, the availability of tax planning strategies, and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with the Company's internal business forecasts. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters.

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1-Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of recent accounting developments affecting the Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. In addition, foreign-currency exchange-rate risk exists due to anticipated foreign-currency-denominated payments and receipts. These risks can affect revenues and cash flows from operating, investing, and financing activities. The Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for natural gas, oil, and NGLs. Management expects energy prices to remain volatile and unpredictable. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 356 Bcf of natural gas at December 31, 2014, with a net derivative asset position of $228 million. Based on actual derivative contractual volumes, a 10% increase in natural-gas prices would reduce the fair value of these derivatives by $60 million, while a 10% decrease in natural-gas prices would increase the fair value of these derivatives by $52 million. However, any cash received or paid to settle these derivatives would be substantially offset by the realized sales value of equivalent production. In 2014, the Company terminated or offset then-existing 2015 oil three-way collars with a notional volume of 25 MBbls/d due to lower oil prices, resulting in a cash receipt of $126 million.

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Derivative Instruments Held for Trading Purposes At December 31, 2014, the Company had a net derivative asset position of $28 million (gains of $28 million) on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

For additional information regarding the Company's marketing and trading portfolio, see *Marketing Activities* under Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK Any borrowings under the New Credit Facilities, the WES RCF, and the commercial paper program are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets is subject to fixed interest rates. The Company's $2.9 billion of LIBOR-based obligations, which are presented on the Company's Consolidated Balance Sheets net of preferred investments in two non-controlled entities, give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. A 10% increase in LIBOR would not impact the Company's interest cost on fixed-rate debt already outstanding, but would affect the fair value of outstanding fixed-rate debt.

At December 31, 2014, the Company had a net derivative liability position of $1.2 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would increase (decrease) the aggregate fair value of outstanding interest-rate swap agreements by approximately $104 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by actual borrowing costs associated with any future debt issuances or borrowings under the New Credit Facilities and the commercial paper program. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 11-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

FOREIGN-CURRENCY EXCHANGE-RATE RISK Anadarko's operating revenues are realized in U.S. dollars, and the predominant portion of Anadarko's capital and operating expenditures are U.S.-dollar-denominated. Exposure to foreign-currency risk generally arises in connection with project-specific contractual arrangements and other commitments. Near-term foreign-currency-denominated expenditures are primarily in euros, Brazilian reais, British pounds sterling, Mozambican meticais, and Colombian pesos. Management periodically enters into various risk-management transactions to mitigate a portion of its exposure to foreign-currency exchange-rate risk.

The Company has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability for its 2008 divestiture of the Peregrino field offshore Brazil, which is currently under consideration by the Brazilian courts. See *Note 17-Contingencies-Other Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. At December 31, 2014, cash of $128 million was held in escrow. A 10% increase or decrease in the foreign-currency exchange rate would not materially impact the Company's gain or loss related to foreign currency.

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Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION

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ANADARKO PETROLEUM CORPORATION

REPORT OF MANAGEMENT

Management prepared, and is responsible for, the Consolidated Financial Statements and the other information appearing in this annual report. The Consolidated Financial Statements present fairly the Company's financial condition, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its Consolidated Financial Statements, the Company includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Company's financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Company's financial records and related data, as well as the minutes of the stockholders' and Directors' meetings.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's internal control system was designed to provide reasonable assurance to the Company's Management and Directors regarding the preparation and fair presentation of published financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2014. This assessment was based on criteria established in the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2014, the Company's internal control over financial reporting was effective based on those criteria. The Company acquired Nuevo Midstream, LLC in November 2014 and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, Nuevo Midstream, LLC's internal control over financial reporting associated with total assets of $1.6 billion and total revenues of $12.5 million included in the consolidated financial statements of Anadarko Petroleum Corporation and subsidiaries as of and for the year ended December 31, 2014.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2014.

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

February 20, 2015

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Assessment of Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Anadarko Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation acquired Nuevo Midstream, LLC in November 2014 and management excluded from its assessment of the effectiveness of Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2014, Nuevo Midstream, LLC's internal control over financial reporting associated with total assets of $1.6 billion and total revenues of $12.5 million included in the consolidated financial statements of Anadarko Petroleum Corporation and subsidiaries as of and for the year ended December 31, 2014. Our audit of internal control over financial reporting of Anadarko Petroleum Corporation also excluded an evaluation of the internal control over financial reporting of Nuevo Midstream, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 20, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 20, 2015

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 20, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 20, 2015

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
millions except per-share amounts	**2014**	2013	2012
Revenues and Other			
Natural-gas sales	$ **3,849**	$ 3,388	$ 2,444
Oil and condensate sales	**9,748**	9,178	8,728
Natural-gas liquids sales	**1,572**	1,262	1,224
Gathering, processing, and marketing sales	**1,206**	1,039	911
Gains (losses) on divestitures and other, net	**2,095**	(286)	104
Total	**18,470**	14,581	13,411
Costs and Expenses			
Oil and gas operating	**1,171**	1,092	976
Oil and gas transportation and other	**1,184**	1,022	955
Exploration	**1,639**	1,329	1,946
Gathering, processing, and marketing	**1,030**	869	763
General and administrative	**1,316**	1,090	1,246
Depreciation, depletion, and amortization	**4,550**	3,927	3,964
Other taxes	**1,244**	1,077	1,224
Impairments	**836**	794	389
Algeria exceptional profits tax settlement	**-**	33	(1,797)
Deepwater Horizon settlement and related costs	**97**	15	18
Total	**13,067**	11,248	9,684
Operating Income (Loss)	**5,403**	3,333	3,727
Other (Income) Expense			
Interest expense	**772**	686	742
(Gains) losses on derivatives, net	**197**	(398)	(326)
Other (income) expense, net	**20**	89	(4)
Tronox-related contingent loss	**4,360**	850	(250)
Total	**5,349**	1,227	162
Income (Loss) Before Income Taxes	**54**	2,106	3,565
Income tax expense (benefit)	**1,617**	1,165	1,120
Net Income (Loss)	**(1,563)**	941	2,445
Net income attributable to noncontrolling interests	**187**	140	54
Net Income (Loss) Attributable to Common Stockholders	$ **(1,750)**	$ 801	$ 2,391
Per Common Share			
Net income (loss) attributable to common stockholders-basic	$ **(3.47)**	$ 1.58	$ 4.76
Net income (loss) attributable to common stockholders-diluted	$ **(3.47)**	$ 1.58	$ 4.74
Average Number of Common Shares Outstanding-Basic	**506**	502	500
Average Number of Common Shares Outstanding-Diluted	**506**	505	502
Dividends (per Common Share)	$ **0.99**	$ 0.54	$ 0.36

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2014**	2013	2012
Net Income (Loss)	**$ (1,563)**	$ 941	$ 2,445
Other Comprehensive Income (Loss)			
Adjustments for derivative instruments			
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**9**	11	12
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(3)**	(4)	(4)
Total adjustments for derivative instruments, net of taxes	**6**	7	8
Adjustments for pension and other postretirement plans			
Net gain (loss) incurred during period	**(405)**	416	(155)
Income taxes on net gain (loss) incurred during period	**149**	(152)	56
Amortization of net actuarial (gain) loss to general and administrative expense	**27**	132	93
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(9)**	(49)	(32)
Amortization of net prior service (credit) cost to general and administrative expense	**-**	1	2
Total adjustments for pension and other postretirement plans, net of taxes	**(238)**	348	(36)
Total	**(232)**	355	(28)
Comprehensive Income (Loss)	**(1,795)**	1,296	2,417
Comprehensive income attributable to noncontrolling interests	**187**	140	54
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (1,982)**	$ 1,156	$ 2,363

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	$ **7,369**	$ 3,698
Accounts receivable (net of allowance of $7 million and $5 million)		
Customers	**1,118**	1,481
Others	**1,409**	1,241
Other current assets	**1,325**	688
Total	**11,221**	7,108
Properties and Equipment		
Cost	**75,107**	71,244
Less accumulated depreciation, depletion, and amortization	**33,518**	30,315
Net properties and equipment	**41,589**	40,929
Other Assets	**2,310**	2,082
Goodwill and Other Intangible Assets	**6,569**	5,662
Total Assets	$ **61,689**	$ 55,781
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ **3,683**	$ 3,530
Current asset retirement obligations	**257**	409
Accrued expenses	**994**	1,264
Current portion of long-term debt	**-**	500
Deepwater Horizon settlement and related costs	**90**	-
Tronox-related contingent liability	**5,210**	-
Total	**10,234**	5,703
Long-term Debt	**15,092**	13,065
Other Long-term Liabilities		
Deferred income taxes	**9,249**	9,245
Asset retirement obligations	**1,796**	1,613
Tronox-related contingent liability	**-**	850
Other	**3,000**	1,655
Total	**14,045**	13,363
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 525.9 million and 522.5 million shares issued)	**52**	52
Paid-in capital	**9,005**	8,629
Retained earnings	**12,125**	14,356
Treasury stock (19.3 million and 18.8 million shares)	**(940)**	(895)
Accumulated other comprehensive income (loss)	**(517)**	(285)
Total Stockholders' Equity	**19,725**	21,857
Noncontrolling interests	**2,593**	1,793
Total Equity	**22,318**	23,650
Total Liabilities and Equity	$ **61,689**	$ 55,781

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

millions	Total Stockholders' Equity: Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2011	$ 51	$ 7,851	$ 11,619	$ (804)	$ (612)	$ 878	$ 18,983
Net income (loss)	-	-	2,391	-	-	54	2,445
Common stock issued	-	249	-	-	-	-	249
Dividends-common stock	-	-	(181)	-	-	-	(181)
Repurchase of common stock	-	-	-	(37)	-	-	(37)
Subsidiary equity transactions	-	130	-	-	-	417	547
Distributions to noncontrolling interest owners	-	-	-	-	-	(112)	(112)
Contributions from noncontrolling interest owners	-	-	-	-	-	16	16
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	-	-	-	-	8	-	8
Adjustments for pension and other postretirement plans	-	-	-	-	(36)	-	(36)
Balance at December 31, 2012	51	8,230	13,829	(841)	(640)	1,253	21,882
Net income (loss)	-	-	801	-	-	140	941
Common stock issued	1	292	-	-	-	-	293
Dividends-common stock	-	-	(274)	-	-	-	(274)
Repurchase of common stock	-	-	-	(54)	-	-	(54)
Subsidiary equity transactions	-	107	-	-	-	554	661
Distributions to noncontrolling interest owners	-	-	-	-	-	(156)	(156)
Contributions from noncontrolling interest owners	-	-	-	-	-	2	2
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	-	-	-	-	7	-	7
Adjustments for pension and other postretirement plans	-	-	-	-	348	-	348
Balance at December 31, 2013	**52**	**8,629**	**14,356**	**(895)**	**(285)**	**1,793**	**23,650**
Net income (loss)	-	-	**(1,750)**	-	-	**187**	**(1,563)**
Common stock issued	-	**286**	-	-	-	-	**286**
Dividends-common stock	-	-	**(505)**	-	-	-	**(505)**
Repurchase of common stock	-	-	-	**(45)**	-	-	**(45)**
Subsidiary equity transactions	-	**90**	**24**	-	-	**829**	**943**
Distributions to noncontrolling interest owners	-	-	-	-	-	**(216)**	**(216)**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	-	-	-	-	**6**	-	**6**
Adjustments for pension and other postretirement plans	-	-	-	-	**(238)**	-	**(238)**
Balance at December 31, 2014	**$ 52**	**$ 9,005**	**$ 12,125**	**$ (940)**	**$ (517)**	**$ 2,593**	**$ 22,318**

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
millions	**2014**	2013	2012
Cash Flows from Operating Activities			
Net income (loss)	**$ (1,563)**	$ 941	$ 2,445
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, and amortization	**4,550**	3,927	3,964
Deferred income taxes	**(105)**	90	164
Dry hole expense and impairments of unproved properties	**1,245**	864	1,544
Impairments	**836**	794	389
(Gains) losses on divestitures, net	**(1,891)**	470	71
Total (gains) losses on derivatives, net	**207**	(392)	(308)
Operating portion of net cash received (paid) in settlement of derivative instruments	**371**	85	685
Other	**327**	246	232
Changes in assets and liabilities			
Deepwater Horizon settlement and related costs	**90**	(2)	24
Algeria exceptional profits tax settlement	**-**	730	(791)
Tronox-related contingent loss	**4,360**	850	(250)
(Increase) decrease in accounts receivable	**103**	(11)	520
Increase (decrease) in accounts payable and accrued expenses	**7**	150	(476)
Other items-net	**(71)**	146	126
Net cash provided by (used in) operating activities	**8,466**	8,888	8,339
Cash Flows from Investing Activities			
Additions to properties and equipment and dry hole costs	**(9,508)**	(7,721)	(7,242)
Acquisition of businesses	**(1,527)**	(473)	-
Divestitures of properties and equipment and other assets	**4,968**	567	657
Other-net	**(405)**	(589)	(284)
Net cash provided by (used in) investing activities	**(6,472)**	(8,216)	(6,869)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**2,879**	958	1,042
Repayments of debt	**(1,425)**	(710)	(3,044)
Financing portion of net cash paid in settlement of derivative instruments	**(222)**	-	-
Increase (decrease) in outstanding checks	**62**	(13)	(69)
Dividends paid	**(505)**	(274)	(181)
Repurchase of common stock	**(45)**	(54)	(37)
Issuance of common stock, including tax benefit on share-based compensation awards	**121**	146	103
Sale of subsidiary units	**1,026**	724	623
Distributions to noncontrolling interest owners	**(216)**	(156)	(112)
Contributions from noncontrolling interest owners	**-**	2	16
Net cash provided by (used in) financing activities	**1,675**	623	(1,659)
Effect of Exchange Rate Changes on Cash	**2**	(68)	(37)
Net Increase (Decrease) in Cash and Cash Equivalents	**3,671**	1,227	(226)
Cash and Cash Equivalents at Beginning of Period	**3,698**	2,471	2,697
Cash and Cash Equivalents at End of Period	**$ 7,369**	$ 3,698	$ 2,471

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of natural gas, oil, condensate, natural gas liquids (NGLs), and anticipated production of liquefied natural gas (LNG). In addition, the Company engages in the gathering, processing, treating, and transporting of natural gas, oil, and NGLs. The Company also participates in the hard-minerals business through royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the United States. The Consolidated Financial Statements include the accounts of Anadarko and entities in which it holds a controlling interest. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities, over which Anadarko has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are reported as a component of other assets. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

Use of Estimates The preparation of financial statements in accordance with generally accepted accounting principles in the United States (GAAP) requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; asset retirement obligations; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1-Inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2-Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3-Inputs that are not observable from objective sources, such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

In determining fair value, the Company uses observable market data when available, or models that incorporate observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. Summary of Significant Accounting Policies (Continued)

In arriving at fair-value estimates, the Company uses relevant observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in *Note 12-Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, asset retirement obligations, exit or disposal costs, and capital lease assets where the present value of lease payments is greater than the fair value of the leased asset.

Revenues The Company's natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. Oil and condensate are sold primarily to marketers, gatherers, and refiners. NGLs are sold primarily to direct end-users, refiners, and marketers.

The Company recognizes sales revenues for natural gas, oil and condensate, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Anadarko provides gathering, processing, treating, and transporting services pursuant to a variety of contracts. Under these arrangements, the Company receives fees, or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time the services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Consolidated Statements of Income.

Marketing margins related to the Company's production are included in natural-gas sales, oil and condensate sales, and NGLs sales. Marketing margins related to sales of commodities purchased from third parties and gains and losses on derivatives related to such marketing activities are included in gathering, processing, and marketing sales in the Consolidated Statements of Income.

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. Under these arrangements, barrels are sold to a third party at a location-based contract price and subsequently repurchased by the Company at a downstream location. The difference in value between the sale and purchase price represents the transportation fee from the lease or certain gathering locations to more liquid markets. These arrangements are often required by private transporters. These transactions are reported on a net basis and included in oil and gas transportation in the Consolidated Statements of Income.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. Summary of Significant Accounting Policies (Continued)

Accounts Receivable and Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued.

Inventories Commodity inventories are stated at the lower of average cost or market.

Properties and Equipment Properties and equipment are stated at cost less accumulated depreciation, depletion, and amortization expense (DD&A). Costs of improvements that appreciably improve the efficiency or productive capacity of existing properties or extend their lives are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs such as exploratory geological and geophysical costs, delay rentals, and exploration overhead are charged against earnings as incurred. If an exploratory well provides evidence to justify potential completion as a producing well, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally in deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory well costs in light of ongoing exploration activities-in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense in the Consolidated Statements of Income.

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1. Summary of Significant Accounting Policies (Continued)

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity method affiliates that are undergoing the construction of assets that have not commenced principle operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. See *Note 12-Debt and Interest Expense.*

Asset Retirement Obligations Asset retirement obligations (AROs) associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of AROs change, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. See *Note 7-Asset Retirement Obligations.*

Impairments Properties and equipment are reviewed for impairment when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. See *Note 5-Impairments.*

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets used in oil and gas activities are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 47 years for gathering facilities.

Goodwill and Other Intangible Assets Goodwill is subject to annual impairment testing at October 1 (or more frequent testing as circumstances dictate). Anadarko has allocated goodwill to the following reporting units: oil and gas exploration and production, other gathering and processing, Western Gas Partners, LP (WES) gathering and processing, and WES transportation. Changes in goodwill may result from, among other things, impairments, future acquisitions, or future divestitures. See *Note 8-Goodwill and Other Intangible Assets.*

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date as well as customer-related intangible assets, including customer relationships established by acquired contracts. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment whenever impairment indicators are present. See *Note 8-Goodwill and Other Intangible Assets.*

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. Summary of Significant Accounting Policies (Continued)

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risk. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, accrued expenses, or other long-term liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the normal purchases and sales exception criteria. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Gains and losses on derivative instruments are recognized currently in earnings. Net losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 11-Derivative Instruments*.

Accounts Payable Accounts payable included liabilities of $388 million at December 31, 2014, and $326 million at December 31, 2013, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in applicable bank accounts. Changes in these liabilities are reflected in cash flows from financing activities.

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for legal contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 17-Contingencies*.

Environmental Contingencies The Company is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. Except for environmental contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with environmental obligations when such losses are probable and reasonably estimable. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 17-Contingencies*.

Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans The Company measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and the health care cost trend rate (for postretirement plans). Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

The Company amortizes prior service costs (credits) on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. See *Note 21-Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. Summary of Significant Accounting Policies (Continued)

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 9-Noncontrolling Interests*.

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). The Company uses the flow-through method to account for its investment tax credits. See *Note 18-Income Taxes*.

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards including stock options and non-vested equity shares (restricted stock awards and units). The Company may also grant equity-classified and liability-classified awards based on a comparison of the Company's total shareholder return (TSR) to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock. For other share-based compensation awards, fair value is determined using a Monte Carlo simulation or discounted-cash-flow methodology.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 15-Share-Based Compensation*.

Earnings Per Share The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and performance-based stock awards, if the inclusion of these items is dilutive. See *Note 13-Stockholders' Equity*.

Recently Issued Accounting Standards The Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*. This ASU supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities-Oil and Gas-Revenue Recognition*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

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1. Summary of Significant Accounting Policies (Continued)

ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity,* changes the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. This ASU is effective beginning in 2015, with early adoption permitted for disposals or for assets classified as held for sale not reported in previously issued financial statements. Anadarko early adopted this ASU on a prospective basis in the first quarter of 2014 with no material impact on the Company's consolidated financial statements.

ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists,* requires that an unrecognized tax benefit or a portion of an unrecognized tax benefit be presented in the financial statements as a reduction to a deferred tax asset, except in certain circumstances. This ASU is effective for annual and interim periods beginning in 2014. See *Note 18-Income Taxes.*

2. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions In November 2014, WES acquired Nuevo Midstream, LLC (Nuevo), which owns and operates gathering and processing assets in the Delaware basin in West Texas, for $1.554 billion. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM). This acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. This acquisition aligns the Company's gas gathering and processing capacity with future industry production growth plans in the Delaware basin. The following summarizes the preliminary fair value of assets acquired and liabilities assumed at the acquisition date, pending the acquired entity's final financial statements:

millions	
Current assets	$ 46
Properties and equipment	441
Other intangible assets	836
Accounts payable	(13)
Accrued expenses	(25)
Deferred income taxes	(1)
Asset retirement obligations	(9)
Goodwill	279
Total assets acquired and liabilities assumed	$ 1,554

Fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of properties and equipment is based on market and cost approaches. Intangible assets consist of customer contracts, the fair value of which was determined using an income approach. Deferred tax assets (liabilities) represent the tax effects of differences in the tax basis and acquisition-date fair values of assets acquired and liabilities assumed. All of the goodwill related to this acquisition is amortizable for tax purposes. The assets acquired and liabilities assumed are included within the midstream reporting segment.

Results of operations attributable to this acquisition are included in the Company's Consolidated Statements of Income from the date acquired. The amounts of revenue and earnings included in the Company's Consolidated Statement of Income for the year ended December 31, 2014, and the amounts of revenue and earnings that would have been recognized had the acquisition occurred on January 1, 2014, are not material to the Company's Consolidated Statements of Income.

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2. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

There were no other material acquisitions made during 2014. The following summarizes acquisitions made during 2013:

millions, except percentages	**Percentage Acquired**	**Cash Paid**
Certain oil and gas properties and related assets in the Moxa area of Wyoming	100%	$ 310 (1)
Gas-gathering systems in the Marcellus shale in north-central Pennsylvania	33.75%	135
Joint venture formed to design, construct, and own two fractionators located in Mont Belvieu, Texas	25%	78
Intrastate pipeline in southwestern Wyoming	100%	28

(1) Includes $306 million that represents the fair value of the oil and gas properties acquired.

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures for the years ended December 31:

millions	**2014**	2013	2012
Proceeds received	**$ 4,968**	$ 567	$ 657
Gains (losses) on divestitures, net	**1,891**	(470)	(71)

Divestitures The 2014 proceeds and net gains were primarily related to assets included in the oil and gas exploration and production reporting segment. The Company sold a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion, recognizing a gain of $1.5 billion. In addition, the Company sold its Chinese subsidiary for $1.075 billion, recognizing a gain of $510 million; sold its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for $500 million, recognizing a gain of $237 million; and sold its interest in the Pinedale/Jonah assets in Wyoming for $581 million. These gains were partially offset by losses of $456 million discussed under *Assets Held for Sale* below.

The 2013 sales proceeds were primarily related to the Company's divestiture of its interests in a soda ash joint venture and certain U.S. onshore and Indonesian oil and gas properties. Net losses were primarily related to the Company's sale of the Pinedale/Jonah assets discussed under *Assets Held for Sale* below, partially offset by the Company's divestiture of its interests in the soda ash joint venture and certain U.S. oil and gas properties. The 2012 sales proceeds were primarily related to U.S. oil and gas properties and net losses were primarily related to Indonesian oil and gas properties.

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2. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

Assets Held for Sale During the fourth quarter of 2014, Anadarko considered certain U.S. onshore assets from the oil and gas exploration and production reporting segment to be held for sale. These assets were remeasured to their fair value using a market approach and Level 2 fair-value measurement, and the Company recognized a loss of $456 million. Gains and losses on assets held for sale are included in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income. Volatility in the current commodity-price environment has reduced the probability that the assets will be sold within one year and the assets are therefore no longer considered held for sale at December 31, 2014. At December 31, 2014, the balances of assets and liabilities associated with assets held for sale were not material.

During the fourth quarter of 2013, the Company began marketing certain other domestic properties from the oil and gas exploration and production reporting segment to redirect its operating activities and capital investments to other areas. These assets were remeasured to their fair value using a market approach and Level 2 fair-value measurement. In 2013, the Company recognized losses of $704 million primarily related to the sale of the Pinedale/Jonah assets in Wyoming, which closed in 2014. At December 31, 2013, the Company's Consolidated Balance Sheets included long-term assets of $616 million and long-term liabilities of $27 million associated with assets held for sale.

Property Exchange In 2013, the Company exchanged certain oil and gas properties in the Wattenberg field with a third party. The properties exchanged were measured at the Company's historical net cost with no gain or loss recognized. Anadarko paid $106 million in cash as part of the exchange, which is included as an addition to properties and equipment on the Company's Consolidated Statement of Cash Flows.

3. Inventories

The following summarizes the major classes of inventories included in other current assets at December 31:

millions	**2014**	2013
Oil	**$ 133**	$ 88
Natural gas	**27**	43
NGLs	**83**	79
Total inventories	**$ 243**	$ 210

4. Properties and Equipment

The following summarizes the cost of properties and equipment by segment at December 31:

millions	**2014**	2013
Oil and gas exploration and production (1)	**$ 63,674**	$ 61,302
Midstream	**8,647**	7,285
Marketing	**-**	9
Other	**2,786**	2,648
Total properties and equipment	**$ 75,107**	$ 71,244

(1) Includes costs associated with unproved properties of $5.1 billion at December 31, 2014, and $6.9 billion at December 31, 2013.

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5. Impairments

The following summarizes impairments by segment for the years ended December 31:

millions	**2014**	2013	2012
Oil and gas exploration and production			
Long-lived assets held for use			
U.S. onshore properties	**$ 545**	$ 142	$ 259
Gulf of Mexico properties	**276**	562	104
Cost-method investment	**3**	11	13
Midstream			
Long-lived assets held for use	**12**	79	13
Total impairments	**$ 836**	$ 794	$ 389

In 2014, certain U.S. onshore and Gulf of Mexico oil and gas properties were impaired primarily due to lower forecasted natural-gas and oil prices. While the Company's other U.S. onshore oil and gas properties indicated no impairment at December 31, 2014, it is reasonably possible the estimate of undiscounted cash flows related to certain of these properties may change in the near term due to declines in commodity prices and could result in additional property impairments.

In 2013, certain Gulf of Mexico properties were impaired due to a reduction in estimated future net cash flows and downward revisions of reserves resulting from changes to the Company's development plans. Also in 2013, certain U.S. onshore properties and related midstream assets were impaired due to downward revisions of reserves resulting from changes to the Company's development plans. In addition, a midstream property was impaired during 2013 due to a reduction in estimated future cash flows. In 2012, certain U.S. onshore and midstream properties were impaired primarily due to lower natural-gas prices and Gulf of Mexico properties were impaired primarily as a result of downward reserves revisions for a property that was near the end of its economic life. Impairments of the Company's Venezuelan cost-method investment were due to declines in estimated recoverable value.

The following summarizes the post-impairment fair value of the above-described assets, which was measured using the income approach and Level 3 inputs:

millions	**2014**	2013
Long-lived assets held for use	**$ 731**	$ 548
Cost-method investment (1)	**32**	32

(1) This represents the Company's after-tax net investment.

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income. In 2012, the Company recognized a $721 million impairment of unproved Powder River coalbed methane properties primarily due to lower natural-gas prices. Also in 2012, the Company recognized a $124 million impairment of an unproved Gulf of Mexico natural-gas property that the Company did not expect to develop under the forecasted natural-gas price environment.

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6. Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs at December 31 for each of the last three years. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

millions	**2014**	2013	2012
Balance at January 1	**$ 2,232**	$ 2,062	$ 1,353
Additions pending the determination of proved reserves	**421**	848	960
Divestitures (1)	**(913)**	(48)	-
Reclassifications to proved properties	**(100)**	(507)	(129)
Charges to exploration expense	**(118)**	(123)	(122)
Balance at December 31	**$ 1,522**	$ 2,232	$ 2,062

(1) Includes $(744) million related to the Company's sale of a 10% working interest in Offshore Area 1 in Mozambique during 2014.

The following summarizes an aging of suspended exploratory well costs by geographic area and the year the costs were suspended at December 31, 2014:

		Year Costs Incurred(1)			
millions	**Total**	**2014**	**2013**	**2012**	**2011 and prior**
United States-Onshore	$ 164	$ 131	$ 17	$ 5	$ 11
United States-Offshore	314	78	80	63	93
International	1,044	179	271	184	410
	$ 1,522	$ 388	$ 368	$ 252	$ 514

(1) Excludes additions subsequently reclassified to proved properties within the same year.

Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling were associated with 24 projects at December 31, 2014, primarily located in Brazil, Ghana, and the Gulf of Mexico. Project costs suspended for longer than one year were primarily suspended pending the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, well-test analysis, additional geological and geophysical data, facilities and infrastructure development options, development plan approval, and permitting. Projects with suspended exploratory well costs are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development and where management is actively pursuing efforts to assess whether reserves can be attributed to these projects. If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

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7. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement. The following summarizes changes in the Company's AROs during 2014 and 2013:

millions	**2014**	2013
Carrying amount of asset retirement obligations at January 1	**$ 2,022**	$ 1,885
Liabilities incurred	**119**	182
Property dispositions	**(70)**	(76)
Liabilities settled	**(443)**	(162)
Accretion expense	**93**	110
Revisions in estimated liabilities	**332**	83
Carrying amount of asset retirement obligations at December 31	**$ 2,053**	$ 2,022

8. Goodwill and Other Intangible Assets

Goodwill The Company's 2014 annual impairment assessment of goodwill indicated no impairment. Procedures were also performed in the fourth quarter of 2014 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices. These procedures also indicated no impairment. At December 31, 2014, the Company had $5.6 billion of goodwill allocated to the following reporting units: $5.1 billion to oil and gas exploration and production, $69 million to other gathering and processing, $379 million to WES gathering and processing, and $5 million to WES transportation.

Significant declines in commodity prices, difficulties or potential delays in obtaining drilling permits, or other unanticipated events could result in further goodwill impairment tests in the near term, the results of which may have a material adverse impact on the Company's results of operations.

Other Intangible Assets Intangible assets and associated amortization expense were as follows:

millions	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Expense
December 31, 2014				
Offshore platform leases	**$ 33**	**$ (29)**	**$ 4**	**$ -**
Customer contracts	**1,004**	**(15)**	**989**	**6**
	$ 1,037	**$ (44)**	**$ 993**	**$ 6**
December 31, 2013				
Offshore platform leases	$ 60	$ (50)	$ 10	$ 3
Customer contracts	169	(9)	160	4
	$ 229	$ (59)	$ 170	$ 7

Customer contract intangible assets are primarily related to WES's DBM acquisition in 2014. These contracts are being amortized over 30 years. See *Note 2-Acquisitions, Divestitures, and Assets Held for Sale*. The annual aggregate amortization expense for intangible assets is expected to be $31 million each of the next five years.

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9. Noncontrolling Interests

In December 2012, Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary formed to own substantially all of the partnership interests in WES previously owned by Anadarko, completed its initial public offering (IPO) of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit, for net proceeds of $411 million. During 2014, Anadarko sold approximately six million WGP common units to the public, raising net proceeds of $335 million. At December 31, 2014, Anadarko's ownership interest in WGP consisted of an 88.3% limited partner interest and the entire non-economic general partner interest. The remaining 11.7% limited partner interest in WGP was owned by the public.

WES, a publicly traded consolidated subsidiary, is a limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. WES issued approximately 10 million common units to the public raising net proceeds of $691 million in 2014, approximately 12 million common units to the public raising net proceeds of $725 million in 2013, and approximately 5 million common units to the public raising net proceeds of $212 million in 2012. In addition, WES issued 11 million Class C units to Anadarko in 2014 to partially fund the DBM acquisition. These units will receive distributions in the form of additional Class C units until the end of 2017. At December 31, 2014, WGP's ownership interest in WES consisted of a 34.9% limited partner interest, the entire 1.8% general partner interest, and all of the WES incentive distribution rights. At December 31, 2014, Anadarko also owned an 8.3% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 55% limited partner interest in WES was owned by the public.

10. Equity-Method Investments

In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable London Interbank Offered Rate (LIBOR) based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2014. Anadarko has legal right of setoff and intends to net settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Consolidated Balance Sheets in other long-term liabilities-other for all periods presented.

Interest on the notes issued by Anadarko is variable, based on LIBOR, plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 1.24% at December 31, 2014 and December 31, 2013. The note payable agreement contains a covenant that provides for a maximum Anadarko debt-to-capital ratio of 67%. Anadarko was in compliance with this covenant at December 31, 2014. Other (income) expense, net includes interest expense on the notes payable of $36 million in 2014, $37 million in 2013, and $42 million in 2012, and equity earnings from Anadarko's investments in the investee entities of $(45) million in 2014, $(42) million in 2013, and $(43) million in 2012.

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11. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations, such as Henry Hub, Louisiana for natural gas and Cushing, Oklahoma or Sullom Voe, Scotland for oil. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio increases (decreases) when interest rates increase (decrease).

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 14-Accumulated Other Comprehensive Income (Loss).*

Oil and Natural-Gas Production/Processing Derivative Activities The natural-gas prices listed below are New York Mercantile Exchange (NYMEX) Henry Hub prices. The following is a summary of the Company's derivative instruments related to natural-gas production/processing derivative activities at December 31, 2014:

	2015 Settlement
Natural Gas	
Three-Way Collars (thousand MMBtu/d)	635
Average price per MMBtu	
Ceiling sold price (call)	$ 4.76
Floor purchased price (put)	$ 3.75
Floor sold price (put)	$ 2.75
Extendable Fixed-Price Contracts (thousand MMBtu/d) (1)	170
Average price per MMBtu	$ 4.17

(1) The extendable fixed-price contracts have a contract term of January 2015 to December 2015 with an option for the counterparty to extend the contract term to December 2016 at the same price.
MMBtu-million British thermal units
MMBtu/d-million British thermal units per day

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

In 2014, the Company terminated or offset then-existing 2015 oil three-way collars with a notional volume of 25 thousand barrels per day due to lower oil prices, resulting in a cash receipt of $126 million.

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11. Derivative Instruments (Continued)

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 6 billion cubic feet (Bcf) at December 31, 2014, and 16 Bcf at December 31, 2013, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR. These swap instruments include a provision that requires both the termination of the swaps and cash settlement in full at the start of the reference period.

To align the interest-rate swap portfolio with anticipated future debt financing, in 2014 the Company extended the reference-period start dates from June 2014 to September 2016 and adjusted the related fixed interest rates for interest-rate swaps with an aggregate notional principal amount of $1.1 billion, and in 2012 the Company extended the reference-period start dates from October 2012 to September 2016 and adjusted the related fixed interest rates for interest-rate swap agreements with an aggregate notional principal amount of $800 million. In addition, in anticipation of the July 2014 issuance of an aggregate $1.25 billion of Senior Notes, interest-rate swap agreements with an aggregate notional principal amount of $750 million were settled in 2014, resulting in a cash payment of $222 million. Interest-rate swap agreements with an aggregate notional principal amount of $200 million were also settled in October 2012, resulting in a cash payment of $64 million.

Derivative settlements are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element and, therefore settlements related to these extended interest-rate derivatives are classified as cash flows from financing activities.

The Company had the following outstanding interest-rate swaps at December 31, 2014:

millions except percentages	Reference Period		Weighted-Average
Notional Principal Amount	Start	End	Interest Rate
$ 50	September 2016	September 2026	5.91%
$ 1,850	September 2016	September 2046	6.05%

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11. Derivative Instruments (Continued)

Effect of Derivative Instruments-Balance Sheet The following summarizes the fair value of the Company's derivative instruments at December 31:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**2014**	2013	**2014**	2013
Commodity derivatives				
Other current assets	**$ 421**	$ 181	**$ (118)**	$ (102)
Other assets	**1**	89	**-**	(66)
Accrued expenses	**71**	106	**(114)**	(149)
Other liabilities	**-**	4	**(6)**	(15)
	493	380	**(238)**	(332)
Interest-rate and other derivatives				
Accrued expenses	**-**	-	**-**	(480)
Other liabilities	**-**	-	**(1,217)**	(174)
	-	-	**(1,217)**	(654)
Total derivatives	**$ 493**	$ 380	**$ (1,455)**	$ (986)

Effect of Derivative Instruments-Statement of Income The following summarizes gains and losses related to derivative instruments:

millions **Classification of (Gain) Loss Recognized**	**2014**	2013	2012
Commodity derivatives			
Gathering, processing, and marketing sales (1)	**$ 10**	$ 6	$ 18
(Gains) losses on derivatives, net	**(589)**	141	(387)
Interest-rate and other derivatives			
(Gains) losses on derivatives, net	**786**	(539)	61
Total (gains) losses on derivatives, net	**$ 207**	$ (392)	$ (308)

(1) Represents the effect of Marketing and Trading Derivative Activities.

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11. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or IntercontinentalExchange, Inc. through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure. The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties.

In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types. At December 31, 2014, $289 million of the Company's $1.455 billion gross derivative liability balance, and at December 31, 2013, $76 million of the Company's $986 million gross derivative liability balance would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declined to below investment grade. However, most of the Company's derivative counterparties maintained secured positions at December 31, 2014, with respect to the Company's derivative liabilities under the Company's $5.0 billion senior secured revolving credit facility ($5.0 billion Facility). In January 2015, the Company's $5.0 billion Facility was replaced by new unsecured facilities under which the Company's derivative counterparties no longer maintain security interests in any of the Company's assets. As a result, the Company may be required from time to time to post collateral of cash or letters of credit based on the negotiated terms of the individual derivative agreements. For information on the Company's revolving credit facilities, see *Note 12-Debt and Interest Expense-Anadarko Revolving Credit Facilities and Commercial Paper Program*.

The aggregate fair value of unsecured derivative instruments with credit-risk-related contingent features for which a net liability position existed was $97 million (net of collateral) at December 31, 2014, and $42 million at December 31, 2013. The current portion of these amounts was included in accrued expenses and the long-term portion of these amounts was included in other long-term liabilities-other on the Company's Consolidated Balance Sheets.

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11. Derivative Instruments (Continued)

Fair Value Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting (1)	Collateral	Total
December 31, 2014						
Assets						
Commodity derivatives						
Financial institutions	**$ -**	**$ 471**	**$ -**	**$ (187)**	**$ (13)**	**$ 271**
Other counterparties	**-**	**22**	**-**	**(2)**	**-**	**20**
Total derivative assets	**$ -**	**$ 493**	**$ -**	**$ (189)**	**$ (13)**	**$ 291**
Liabilities						
Commodity derivatives						
Financial institutions	**$ -**	**$ (234)**	**$ -**	**$ 187**	**$ 23**	**$ (24)**
Other counterparties	**-**	**(4)**	**-**	**2**	**-**	**(2)**
Interest-rate and other derivatives	**-**	**(1,217)**	**-**	**-**	**-**	**(1,217)**
Total derivative liabilities	**$ -**	**$ (1,455)**	**$ -**	**$ 189**	**$ 23**	**$ (1,243)**
December 31, 2013						
Assets						
Commodity derivatives						
Financial institutions	$ -	$ 211	$ -	$ (153)	$ -	$ 58
Other counterparties	-	169	-	(126)	-	43
Total derivative assets	$ -	$ 380	$ -	$ (279)	$ -	$ 101
Liabilities						
Commodity derivatives						
Financial institutions	$ -	$ (200)	$ -	$ 153	$ 7	$ (40)
Other counterparties	-	(132)	-	126	-	(6)
Interest-rate and other derivatives	-	(654)	-	-	-	(654)
Total derivative liabilities	$ -	$ (986)	$ -	$ 279	$ 7	$ (700)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

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12. Debt and Interest Expense

Debt The Company's outstanding debt is senior unsecured, except for borrowings, if any, under the $5.0 billion Facility. See *Note 10-Equity-Method Investments* for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following summarizes the Company's outstanding debt:

	December 31,	
millions	**2014**	2013
5.750% Senior Notes due 2014	**$ -**	$ 275
7.625% Senior Notes due 2014	**-**	500
5.950% Senior Notes due 2016	**1,750**	1,750
6.375% Senior Notes due 2017	**2,000**	2,000
7.050% Debentures due 2018	**114**	114
WES 2.600% Senior Notes due 2018	**350**	250
6.950% Senior Notes due 2019	**300**	300
8.700% Senior Notes due 2019	**600**	600
WES 5.375% Senior Notes due 2021	**500**	500
WES 4.000% Senior Notes due 2022	**670**	670
3.450% Senior Notes due 2024	**625**	-
6.950% Senior Notes due 2024	**650**	650
7.500% Debentures due 2026	**112**	112
7.000% Debentures due 2027	**54**	54
7.125% Debentures due 2027	**150**	150
6.625% Debentures due 2028	**17**	17
7.150% Debentures due 2028	**235**	235
7.200% Debentures due 2029	**135**	135
7.950% Debentures due 2029	**117**	117
7.500% Senior Notes due 2031	**900**	900
7.875% Senior Notes due 2031	**500**	500
Zero-Coupon Senior Notes due 2036	**2,360**	2,360
6.450% Senior Notes due 2036	**1,750**	1,750
7.950% Senior Notes due 2039	**325**	325
6.200% Senior Notes due 2040	**750**	750
4.500% Senior Notes due 2044	**625**	-
WES 5.450% Senior Notes due 2044	**400**	-
7.730% Debentures due 2096	**61**	61
7.500% Debentures due 2096	**78**	78
7.250% Debentures due 2096	**49**	49
WES revolving credit facility	**510**	-
Total debt at face value	**$ 16,687**	$ 15,202
Net unamortized discounts and premiums (1)	**(1,616)**	(1,645)
Total borrowings	**$ 15,071**	$ 13,557
Capital lease obligation	**21**	8
Less current portion of long-term debt	**-**	500
Total long-term debt	**$ 15,092**	$ 13,065

(1) Unamortized discounts and premiums are amortized over the term of the related debt.

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12. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero-Coupon Senior Notes due 2036 (Zero Coupons). The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of approximately $2.4 billion, reflecting a yield to maturity of 5.24%. The Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $765 million at December 31, 2014. Anadarko's Zero Coupons are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $17.4 billion at December 31, 2014, and $15.3 billion at December 31, 2013.

Debt Activity The following summarizes the Company's debt activity during 2014 and 2013:

millions	Carrying Value	Description
Balance at December 31, 2012	$ 13,269	
Issuances	250	WES 2.600% Senior Notes due 2018
Borrowings	710	WES revolving credit facility
Repayments	(710)	WES revolving credit facility
Other, net	38	Amortization of debt discounts and premiums
Balance at December 31, 2013	$ 13,557	
Issuances	**101**	WES 2.600% Senior Notes due 2018
	394	WES 5.450% Senior Notes due 2044
	624	3.450% Senior Notes due 2024
	621	4.500% Senior Notes due 2044
Borrowings	**1,160**	WES revolving credit facility
Repayments	**(500)**	7.625% Senior Notes due 2014
	(275)	5.750% Senior Notes due 2014
	(650)	WES revolving credit facility
Other, net	**39**	Amortization of debt discounts and premiums
Balance at December 31, 2014	**$ 15,071**	

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12. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facilities and Commercial Paper Program During 2014, the Company maintained the $5.0 billion Facility maturing in September 2015. Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko had to lenders or their affiliates pursuant to certain derivative instruments that were supported by the $5.0 billion Facility as discussed in *Note 11-Derivative Instruments*, were guaranteed by certain of the Company's wholly owned domestic subsidiaries, and were secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries. During 2014, the Company had no outstanding borrowings under the $5.0 billion Facility.

In June 2014, Anadarko entered into a $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility), which is expandable to $4.0 billion, and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). The new facilities (collectively, the New Credit Facilities) replaced the $5.0 billion Facility upon satisfaction of certain conditions, including the January 2015 settlement payment related to the Tronox Adversary Proceeding. For additional information, see *Note 17-Contingencies-Tronox Litigation*.

In January 2015, the Company borrowed $1.5 billion under the 364-Day Facility. Borrowings under the New Credit Facilities generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The New Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65%, and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes.

In January 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes.

WES Borrowings In February 2014, WES amended and restated its then-existing $800 million senior unsecured revolving credit facility by entering into a five-year, $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (RCF), which is expandable to a maximum of $1.5 billion. Borrowings under the RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45% depending on WES's credit rating, or the greatest of (i) rates at a margin above the one-month LIBOR, (ii) the federal funds rate, or (iii) prime rates offered by certain designated banks. At December 31, 2014, WES was in compliance with all covenants contained in its RCF, had outstanding borrowings under its RCF of $510 million at an interest rate of 1.47%, and had available borrowing capacity of approximately $677 million ($1.2 billion capacity, less $510 million of outstanding borrowings and $13 million of outstanding letters of credit).

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12. Debt and Interest Expense (Continued)

Scheduled Maturities Total principal amount of debt maturities for the five years ending December 31, 2019, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holder to the Company annually, were as follows:

millions	Principal Amount of Debt Maturities
2015	$ -
2016	1,750
2017	2,000
2018	464
2019	1,410

Interest Expense The following summarizes interest expense for the years ended December 31:

millions	**2014**	2013	2012
Debt and other	**$ 973**	$ 949	$ 963
Capitalized interest	**(201)**	(263)	(221)
Total interest expense	**$ 772**	$ 686	$ 742

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13. Stockholders' Equity

Common Stock The following summarizes the changes in the Company's outstanding shares of common stock:

millions	**2014**	2013	2012
Shares of common stock issued			
Shares at January 1	**523**	519	516
Exercise of stock options	**2**	2	1
Issuance of restricted stock	**1**	2	2
Shares at December 31	**526**	523	519
Shares of common stock held in treasury			
Shares at January 1	**19**	18	18
Shares received for restricted stock vested and options exercised	**-**	1	-
Shares at December 31	**19**	19	18
Shares of common stock outstanding at December 31	**507**	504	501

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders for the years ended December 31:

millions except per-share amounts	**2014**	2013	2012
Net income (loss)			
Net income (loss) attributable to common stockholders	**$ (1,750)**	$ 801	$ 2,391
Less distributions on participating securities	**4**	2	1
Less undistributed income allocated to participating securities	**-**	4	14
Basic	**$ (1,754)**	$ 795	$ 2,376
Diluted	**$ (1,754)**	$ 795	$ 2,376
Shares			
Average number of common shares outstanding-basic	**506**	502	500
Dilutive effect of stock options	**-**	3	2
Average number of common shares outstanding-diluted	**506**	505	502
Excluded (1)	**11**	4	6
Net income (loss) per common share			
Basic	**$ (3.47)**	$ 1.58	$ 4.76
Diluted	**$ (3.47)**	$ 1.58	$ 4.74
Dividends per common share	**$ 0.99**	$ 0.54	$ 0.36

(1) Inclusion of certain shares would have had an anti-dilutive effect.

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14. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2013	$ (54)	$ (231)	$ (285)
Other comprehensive income (loss), before reclassifications	**-**	**(256)**	**(256)**
Reclassifications to Consolidated Statement of Income	**6**	**18**	**24**
Net other comprehensive income (loss)	**6**	**(238)**	**(232)**
Balance at December 31, 2014	**$ (48)**	**$ (469)**	**$ (517)**

15. Share-Based Compensation

At December 31, 2014, 21 million shares of the 31 million shares of Anadarko common stock originally authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. The following summarizes share-based compensation expense for the years ended December 31:

millions	**2014**	2013	2012
Restricted stock	**$ 144**	$ 122	$ 103
Stock options	**21**	27	43
Other equity-classified awards	**1**	1	1
Value creation plan	**136**	-	(2)
Performance-based unit awards	**23**	4	8
Other performance-based awards	**-**	-	165
Other liability-classified awards	**-**	1	2
Pretax compensation expense	**$ 325**	$ 155	$ 320
Income tax benefit	**$ 120**	$ 57	$ 117

Cash flows from financing activities included excess tax benefits related to share-based compensation of $22 million in 2014, $11 million in 2013, and $51 million in 2012. Cash received from stock option exercises was $99 million in 2014, $135 million in 2013, and $52 million in 2012.

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15. Share-Based Compensation (Continued)

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders do not have the right to vote. Restricted stock vests over service periods ranging from the date of grant up to three years and is not considered issued and outstanding until vested.

Non-employee directors are granted deferred shares, which are also considered restricted stock, that are held in a grantor trust by the Company until payable. Non-employee directors may receive these shares in a lump-sum payment or in annual installments.

The following summarizes the Company's restricted stock activity:

	Shares *(millions)*	Weighted-Average Grant-Date Fair Value *(per share)*
Non-vested at January 1, 2014	3.22	$ 82.53
Granted	2.05	$ 87.42
Vested	(1.52)	$ 82.35
Forfeited	(0.15)	$ 84.49
Non-vested at December 31, 2014	3.60	$ 85.31

The weighted-average grant-date fair value per share of restricted stock granted was $84.17 during 2013 and $79.97 during 2012. The total fair value of restricted shares vested was $132 million during 2014, $110 million during 2013, and $105 million during 2012, based on the market price at the vesting date. At December 31, 2014, total unrecognized compensation cost related to restricted stock of $199 million is expected to be recognized over a weighted-average remaining service period of 1.9 years.

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15. Share-Based Compensation (Continued)

Stock Options Certain employees may be granted nonqualified options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options generally vest over three years from the date of grant and terminate at the earlier of the date of exercise or seven years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model with the following assumptions:

- *Expected life*-Based on historical exercise behavior.
- *Volatility*-Based on an average of historical volatility over the expected life of an option and the 12-month average implied volatility.
- *Risk-free interest rates*-Based on the U.S. Treasury rate over the expected life of an option.
- *Dividend yield*-Based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option.
- *Expected forfeiture*-Based on historical forfeiture experience.

The Company used the following weighted-average assumptions to estimate the fair value of stock options granted:

	2014	2013	2012
Weighted-average grant-date fair value	**$ 23.55**	$ 26.27	$ 25.84
Assumptions			
Expected option life-years	**4.9**	4.8	4.9
Volatility	**29.9%**	33.9%	44.2%
Risk-free interest rate	**1.6%**	1.3%	0.7%
Dividend yield	**1.1%**	0.8%	0.5%

The following summarizes the Company's stock option activity:

	Shares *(millions)*	**Weighted-Average Exercise Price** *(per share)*	**Weighted-Average Remaining Contractual Term** *(years)*	**Aggregate Intrinsic Value** *(millions)*
Outstanding at January 1, 2014	7.72	$ 63.30		
Granted	0.95	$ 93.34		
Exercised (1)	(1.85)	$ 54.03		
Forfeited or expired	(0.03)	$ 76.00		
Outstanding at December 31, 2014	6.79	$ 69.96	3.56	$ 104.3
Vested or expected to vest at December 31, 2014	6.73	$ 69.79	3.54	$ 104.2
Exercisable at December 31, 2014	4.99	$ 62.91	2.60	$ 101.1

(1) The total intrinsic value of stock options exercised was $88 million during 2014, $80 million during 2013, and $49 million during 2012, based on the difference between the market price at the exercise date and the exercise price.

At December 31, 2014, total unrecognized compensation cost related to stock options of $40 million is expected to be recognized over a weighted-average remaining service period of 2.2 years.

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15. Share-Based Compensation (Continued)

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offers an incentive compensation program that provides non-officer employees the opportunity to earn cash bonus awards based on the Company's TSR for the year, compared to the TSR of a predetermined group of peer companies. The Company paid zero during 2014 and 2013 related to the plan and $24 million during 2012. At December 31, 2014, the Company had $137 million outstanding liability attributable to the 2014 performance period.

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with two- and three-year performance periods. The vesting of these units is based on comparing the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period. Each performance unit represents the value of one share of the Company's common stock. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $12 million related to vested performance units in 2014, $15 million in 2013, and $37 million in 2012. At December 31, 2014, the Company's liability under Performance Unit Award Agreements was $26 million, with total unrecognized compensation cost related to these awards of $43 million expected to be recognized over a weighted-average remaining performance period of 2.2 years.

Other Performance-Based Awards Prior to 2011, certain officers of the general partner of WES were awarded general partner Unit Appreciation Rights (UARs) pursuant to the Western Gas Holdings, LLC Equity Incentive Plan. The fair value of the UARs was determined based on the fair value of WES's general partner, as determined by the WGP IPO price. The Company paid $203 million related to the UARs upon the WGP IPO in 2012 in settlement of obligations related to all awards then outstanding.

16. Commitments

Operating Leases At December 31, 2014, the Company had $2.7 billion in long-term drilling rig commitments that satisfy operating lease criteria. The Company also had $324 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. These operating leases expire at various dates through 2026. Certain of these operating leases contain residual value guarantees at the end of the lease term, totaling $53 million at December 31, 2014. No liability has been accrued for residual value guarantees. In addition, these operating leases include options to purchase the leased property during or at the end of the lease term for the fair market value or other specified amount at that time. The following summarizes future minimum lease payments under operating leases at December 31, 2014:

millions		
2015	$	1,022
2016		833
2017		592
2018		324
2019		203
Later years		87
Total future minimum lease payments	$	3,061

Anadarko has entered into various agreements to secure drilling rigs necessary to support the execution of its drilling plans over the next several years. The table of future minimum lease payments above includes $2.5 billion related to seven offshore drilling vessels and $208 million related to certain contracts for U.S. onshore drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells, net of amounts billed to partners, will initially be capitalized as a component of oil and gas properties, and either depreciated or impaired in future periods or written off as exploration expense.

Total rent expense, net of sublease income and amounts capitalized, amounted to $85 million in 2014, $119 million in 2013, and $136 million in 2012. Total rent expense includes contingent rent expense related to transportation and processing fees of $22 million in 2014, $24 million in 2013, and $28 million in 2012.

Other Commitments In the normal course of business, the Company enters into other contractual agreements for processing, treating, transportation, and storage of natural gas, oil, and NGLs, as well as for other oil and gas activities. These agreements expire at various dates through 2036. At December 31, 2014, aggregate future payments under these contracts totaled $10.4 billion, of which $2.2 billion is expected to be paid in 2015, $1.6 billion in 2016, $1.3 billion in 2017, $1.2 billion in 2018, $1.0 billion in 2019, and $3.1 billion thereafter.

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17. Contingencies

Litigation The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including, but not limited to, personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. The Company's Consolidated Balance Sheets include liabilities of $5.3 billion at December 31, 2014, and $854 million at December 31, 2013, for litigation-related contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

Tronox Litigation On November 28, 2005, Tronox Incorporated (Tronox), at the time a subsidiary of Kerr-McGee Corporation, completed an IPO and was subsequently spun-off from Kerr-McGee Corporation. In August 2006, Anadarko acquired all of the stock of Kerr-McGee Corporation. In January 2009, Tronox and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court), which is the court that presided over the Adversary Proceeding (defined below). In May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) asserting several claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleged, among other things, that it was insolvent or undercapitalized at the date of its IPO and sought, among other things, to recover damages in excess of $18.85 billion from Kerr-McGee and Anadarko, as well as interest and attorneys' fees and costs. In accordance with Tronox's Bankruptcy Court-approved Plan of Reorganization (Plan), the Adversary Proceeding was pursued by a litigation trust (Litigation Trust). Pursuant to the Plan, the Litigation Trust was "deemed substituted" for the Tronox plaintiffs in the Adversary Proceeding. For purposes of this Form 10-K, references to "Tronox" after February 2011 refer to the Litigation Trust.

The U.S. government intervened in the Adversary Proceeding, and in May 2009 asserted separate claims against Anadarko and Kerr-McGee under the Federal Debt Collection Procedures Act (FDCPA Complaint). The Litigation Trust and the U.S. government agreed that the recovery of damages under the Adversary Proceeding, if any, would cover both the Adversary Proceeding and the FDCPA Complaint.

Liability Accrual On April 3, 2014, Anadarko and Kerr-McGee entered into a settlement agreement with the Litigation Trust and the U.S. government (in its capacity as plaintiff-intervenor and acting for and on behalf of certain U.S. government agencies) to resolve all claims asserted in the Adversary Proceeding and FDCPA Complaint for $5.15 billion, which represents principal of approximately $3.98 billion plus 6% interest from the filing of the Adversary Proceeding on May 12, 2009, through April 3, 2014. In addition, the Company agreed to pay interest on the above amount from April 3, 2014, through the payment of the settlement, with an annual interest rate of 1.5% for the first 180 days and 1.5% plus the one-month LIBOR thereafter. Under the terms of the settlement agreement, the Litigation Trust, Anadarko, and Kerr-McGee agreed to mutually release all claims that were or could have been asserted in the Adversary Proceeding. The U.S. government (representing federal agencies that filed claims in the Tronox bankruptcy), Anadarko, and Kerr-McGee also provided covenants not to sue each other with respect to certain claims and causes of action. The U.S. government also provided contribution protection from third-party claims seeking reimbursement from Anadarko and certain of its affiliates for the sites identified in the settlement agreement. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012**

17. Contingencies (Continued)

Anadarko recognized Tronox-related contingent losses of $850 million in the fourth quarter of 2013 and $4.3 billion in the first quarter of 2014. In addition, Anadarko recognized settlement-related interest expense of $60 million, included in Tronox-related contingent loss in the Company's Consolidated Statement of Income, during the year ended December 31, 2014, for an aggregate $5.2 billion Tronox-related contingent liability on the Company's Consolidated Balance Sheet at December 31, 2014. For information on the tax effects of the Tronox settlement agreement, see *Note 18-Income Taxes*.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement), under which the Company paid $4.0 billion in cash and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 (Lease) to BP. Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP (OA). This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims.

Liability Accrual Below is a discussion of the Company's current analysis, under applicable accounting guidance, of its potential liability for (i) amounts invoiced by BP under the OA (OA Liabilities), (ii) OPA-related environmental costs, and (iii) other contingent liabilities. Applicable accounting guidance requires the Company to accrue a liability if both (a) it is probable that a liability has been incurred and (b) the amount of that liability can be reasonably estimated.

The Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and other potential liabilities. The Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. The Company has not recorded a liability for any costs that are subject to indemnification by BP.

OA Liabilities Pursuant to the Settlement Agreement, all amounts deemed by BP to have been due under the OA, as well as all future amounts that otherwise would be invoiced to Anadarko under the OA, have been satisfied.

OPA-Related Environmental Costs BP, Anadarko, and other parties, including parties that do not own an interest in the Lease, such as the drilling contractor, have received correspondence from the U.S. Coast Guard (USCG) referencing their identification as a "responsible party or guarantor" (RP) under OPA. Under OPA, RPs, including Anadarko, may be jointly and severally liable for costs of well control, spill response, and containment and removal of hydrocarbons, as well as other costs and damage claims related to the spill and spill cleanup. The USCG's identification of Anadarko as an RP arises as a result of Anadarko's status as a co-lessee in the Lease.

Under accounting guidance applicable to environmental liabilities, a liability is presumed probable if the entity is both identified as an RP and associated with the environmental event. The Company's co-lessee status in the Lease at the time of the event and the subsequent identification and treatment of the Company as an RP satisfies these standards and therefore establishes the presumption that the Company's potential environmental liabilities related to the Deepwater Horizon events are probable.

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ANADARKO PETROLEUM CORPORATION
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YEARS ENDED DECEMBER 31, 2014, 2013, AND 2012

17. Contingencies (Continued)

As BP funds OPA-related environmental costs, any potential joint and several liability for these costs is satisfied for all RPs, including Anadarko. This bears significance in that once these costs are funded by BP, such costs are no longer analyzed as OPA-related environmental costs, but instead are analyzed as OA Liabilities. As discussed above, Anadarko has settled its OA Liabilities with BP. Thus, potential liability to the Company for OPA-related environmental costs can arise only where BP does not, or otherwise is unable to, fund all of the OPA-related environmental costs. Under this scenario, the joint and several nature of the liability for these costs could cause the Company to recognize a liability for OPA-related environmental costs. However, the Company is fully indemnified by BP against these costs (including guarantees by BPCNA or BP p.l.c.).

Gross OPA-Related Environmental Cost Estimate In prior periods through the fourth quarter of 2011, the Company provided an estimated range of gross OPA-related environmental costs for all identified RPs. This estimate was comprised of spill-response costs and OPA damage claims and was derived from cost information received by the Company from BP. The Company no longer receives Deepwater Horizon-related cost and claims data from BP. Accordingly, the OPA-related environmental cost estimate included in BP's public releases is the best data available to the Company.

Based on information included in BP p.l.c.'s public release on February 3, 2015, gross OPA-related environmental costs are estimated to be $11.0 billion, excluding (i) amounts BP has already funded, which constitute settled OA Liabilities; (ii) amounts that in BP's view cannot reasonably be estimated, which include NRD claims and other litigation damages; (iii) non-OPA-related fines and penalties that may be assessed against Anadarko, including assessments under the Clean Water Act (CWA); and (iv) estimated state and local governmental claims, which BP no longer publicly discloses and, as a result, Anadarko cannot estimate. Actual gross OPA-related environmental costs may vary from those estimated by BP p.l.c. in its public releases, perhaps materially from the above estimate.

Allocable Share of Gross OPA-Related Environmental Costs Under applicable accounting guidance, the Company is required to estimate its allocable share of gross OPA-related environmental costs. To date, BP has paid all Deepwater Horizon event-related costs, which satisfies the Company's potential liability for these costs. Additionally, BP has repeatedly stated publicly and in congressional testimony that it will continue to pay these costs. BP's funding and public commentary has continued subsequent to the release of BP's own investigation report, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling's final report, and the Deepwater Horizon Joint Investigation Team final report, which the Company considers to be significant positive indications in assessing the likelihood of BP continuing to fund all of these costs. Based on BP's stated intent to continue funding these costs, the Company's assessment of BP's financial ability to continue funding these costs, and the impact of BP's settlements with both of its OA partners, the Company believes the likelihood of BP not continuing to satisfy these claims to be remote. Accordingly, the Company considers zero to be its allocable share of gross OPA-related environmental costs and, consistent with applicable accounting guidance, has not recorded a liability for these amounts.

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17. Contingencies (Continued)

Penalties and Fines These costs include amounts that may be assessed as a result of potential civil and/or criminal penalties under various federal, state, and/or local statutes and/or regulations as a result of the Deepwater Horizon events, including, for example, the CWA, the Outer Continental Shelf Lands Act, the Migratory Bird Treaty Act, and possibly other federal, state, and local laws. The foregoing does not represent an exhaustive list of statutes and regulations that potentially could trigger a penalty or fine assessment against the Company. To date, no penalties or fines have been assessed against the Company. However, in December 2010, the U.S. Department of Justice (DOJ), on behalf of the United States, filed a civil lawsuit in the U.S. District Court in New Orleans, Louisiana (Louisiana District Court) against several parties, including the Company, seeking an assessment of civil penalties under the CWA in an amount to be determined by the Louisiana District Court. In February 2012, the Louisiana District Court entered a declaratory judgment that, as a partial owner of the Macondo well, Anadarko is liable for civil penalties under Section 311 of the CWA. The declaratory judgment, which was affirmed in June 2014 by the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit), addresses liability only, and does not address the amount of any civil penalty. The assessment of a civil penalty against Anadarko will follow a bench trial, which began in January 2015.

In July 2014, Anadarko filed a motion for rehearing with the Fifth Circuit requesting that the full court sit to reconsider Anadarko's appeal concerning that portion of the February 2012 declaratory judgment which found Anadarko liable for civil penalties under the CWA. In September 2014, Anadarko filed a letter notifying the Fifth Circuit that the Louisiana District Court issued Findings of Fact and Conclusions of Law in the first phase of the Deepwater Horizon trial (Phase I Findings and Conclusions), which included facts that contradict certain key facts assumed by the Fifth Circuit panel in its June 2014 decision. In January 2015, the Fifth Circuit denied the petition for full court reconsideration with six of the thirteen participating justices filing a dissent.

Applicable accounting guidance requires the Company to accrue a liability if it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. The Louisiana District Court's declaratory judgment in February 2012 satisfies the requirement that a liability arising from the future assessment of a civil penalty against Anadarko is probable. In an effort to resolve this matter, the Company made a settlement offer to the DOJ in July 2014 of $90 million and recorded a contingent liability for this amount at June 30, 2014. The Company subsequently engaged in further discussions regarding settlement, but the parties have not been able to reach agreement on either the amount of, or the terms and conditions governing, a settlement. The Company's settlement offer of $90 million remains outstanding and the Company remains open to resolving the matter through settlement discussions. The Company believes that $90 million under a settlement scenario is a better estimate of loss at this time than any other amount. Based on the above accounting guidance, the Company's contingent liability for CWA penalties and fines remains $90 million at December 31, 2014. However, the Company may ultimately incur a liability related to CWA penalties in excess of the current accrued liability.

The actual amount of a CWA penalty is subject to uncertainty, including whether the Company will be able to reach a settlement with the DOJ or will await the Louisiana District Court's opinion following the bench trial. The CWA sets forth subjective criteria to be considered by the court in assessing the magnitude of any CWA penalty, including the degree of fault of the owner. In the Phase I and II trials (defined below) and again for the penalty phase trial in January 2015, the Louisiana District Court ruled that no evidence of Anadarko's alleged culpability or fault may be presented. In addition, in its Phase I Findings and Conclusions, the Louisiana District Court did not allocate any fault to Anadarko. Given the subjective nature of the CWA criteria used to determine penalty assessments and the Louisiana District Court's prior rulings related to culpability and allocation of fault, the Company currently cannot reasonably estimate the amount of any such penalty to be assessed or determine a reasonable range of potential loss if the matter is resolved by the Louisiana District Court following trial. However, given the Company's lack of direct operational involvement in the event, the Louisiana District Court's rulings excluding any evidence of Anadarko's alleged culpability or fault, the Phase I Findings and Conclusions that did not allocate any fault to Anadarko, and the subjective criteria of the CWA, the Company believes that any CWA penalties assessed to it will not materially impact the Company's financial condition, results of operations, or cash flows.

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17. Contingencies (Continued)

Events or factors that could assist the Company in estimating the amount of settlement or potential civil penalty or a range of potential loss related to such penalty include (i) an assessment by the DOJ, (ii) a ruling by a court of competent jurisdiction, or (iii) substantive settlement negotiations between the Company and the DOJ.

As discussed below, numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. Certain state and local governments appealed, or provided indication of a likely appeal of, the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. For example, eleven Louisiana Parish District Attorneys appealed that decision to the Fifth Circuit. In February 2014, the Fifth Circuit denied the appeal and upheld the Louisiana District Court's decision. In October 2014, the United States Supreme Court denied the Parish District Attorneys' petition to review the case. While that denial ends further appeal of that decision by the eleven Parish District Attorneys, any other party subject to the decision who has not yet appealed, including private parties who opted out of the BP settlement, the states, and other local governments, may do so after obtaining a final judgment on their damages claims. If any further appeal is taken and is successful, state and/or local laws and regulations could become sources of penalties or fines against the Company.

Natural Resource Damages This category includes future damage claims that may be made by federal and/or state natural resource trustee agencies at the completion of injury assessments and restoration planning. Natural resources generally include land, fish, water, air, wildlife, and other such resources belonging to, managed by, held in trust by, or otherwise controlled by, the federal, state, or local government.

The NRD-assessment process is led by government agencies that act as trustees of natural resources on behalf of the public. Government agencies involved in the process include the Department of Commerce, the Department of the Interior (DOI), and the Department of Defense. These governmental departments, along with the five affected states - Alabama, Florida, Louisiana, Mississippi, and Texas - are referred to as the "Co-Trustees." The Co-Trustees continue to conduct injury assessment and restoration planning.

The DOJ civil lawsuit filed against BP, the Company, and others seeks unspecified damages for injury to federal natural resources. Not all of the Co-Trustees were a party to this lawsuit; however, during the second quarter of 2011, the states of Alabama and Louisiana each filed NRD-related state law claims against the Company in the Louisiana District Court. In November 2011, after ruling that only federal law applies, the Louisiana District Court dismissed all the NRD-related state law claims asserted against the Company by the states of Alabama and Louisiana. In April 2013, the states of Texas and Mississippi filed NRD-related state law claims against the Company, which were consolidated in the federal Multidistrict Litigation (MDL) action before the Louisiana District Court discussed below and are stayed until further order of the Louisiana District Court.

NRD claims are generally sought after the damage assessment and restoration planning is completed, which may take several years. Thus, the Company remains unable to reasonably estimate the magnitude of any NRD claim. The Company anticipates that BP will satisfy any NRD claim, which eliminates any potential liability to Anadarko for such costs. In the event any NRD damage claim is made directly against Anadarko, the Company is fully indemnified by BP against such claims (including guarantees by BPCNA or BP p.l.c.).

Civil Litigation Damage Claims Numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company by, among others, fishing, boating, and shrimping enterprises and industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the States of Alabama, Louisiana, Texas, and Mississippi, and several of their political subdivisions; the DOJ; environmental non-governmental organizations; and certain Mexican states. Many of the lawsuits filed assert various claims of negligence, gross negligence, and violations of several federal and state laws and regulations, including, among others, OPA; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Air Act; the CWA; and the Endangered Species Act; or challenge existing permits for operations in the Gulf of Mexico. Generally, the plaintiffs are seeking actual damages, punitive damages, declaratory judgment, and/or injunctive relief.

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17. Contingencies (Continued)

This litigation has been consolidated into a federal MDL action pending before Judge Carl Barbier in the Louisiana District Court. In March 2012, BP and the Plaintiffs' Steering Committee (PSC) entered into a settlement agreement to resolve a substantial majority of the economic loss and medical claims stemming from the Deepwater Horizon events, which the Louisiana District Court approved in orders issued in December 2012 and January 2013. Only OPA claims seeking economic loss damages against the Company remain. In addition, other than those who previously appealed unsuccessfully, certain state and local governments have provided indication of a likely appeal of the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. Certain Mexican states also have appealed the dismissal of their claims against BP, the Company, and others. The Company, pursuant to the Settlement Agreement, is fully indemnified by BP against losses arising as a result of claims for damages, irrespective of whether such claims are based on federal (including OPA) or state law.

The first phase of the trial in the MDL (Phase I) commenced in February 2013. The PSC, BP, BP America Production Company (BPAP), BP p.l.c., the United States, state and local governments, Halliburton Energy Services, Inc. (Halliburton), and certain subsidiaries of Transocean Ltd. (Transocean) participated in Phase I. Anadarko was excused from participation in Phase I. The issues tried in Phase I included the cause of the blowout and all related events leading up to April 22, 2010, the date the *Deepwater Horizon* sank, as well as allocation of fault. In September 2014, the Louisiana District Court issued its Phase I Findings and Conclusions. The Louisiana District Court found that BP and BPAP, Transocean, and Halliburton, but not Anadarko, are each liable under general maritime law for the blowout, explosion, and oil spill. The court determined that BP's and BPAP's conduct was reckless and that both Transocean's and Halliburton's conduct was negligent. The Louisiana District Court apportioned 67% of the fault to BP and BPAP, 30% to Transocean, and 3% to Halliburton. No fault was allocated to Anadarko. BP is challenging certain of the Louisiana District Court's findings.

The second phase of trial (Phase II) began in September 2013 and in November 2013 the parties rested their Phase II cases. The issues tried in Phase II included spill-source control and quantification of the spill for the period from April 20, 2010, until the well was capped. The Company, the PSC, BP, BPAP, BP p.l.c., the United States, state and local governments, Halliburton, and Transocean participated in Phase II of the trial. In January 2015, the Louisiana District Court issued its Phase II Findings of Fact and Conclusions of Law. The Louisiana District Court found that, for purposes of calculating the maximum possible civil penalty under the CWA, 3.19 million barrels of oil were discharged into the Gulf of Mexico.

The penalty phase of the trial began in January 2015. Post-trial briefs are due in March and April 2015. The trial included Anadarko, BP, and the United States, and will assess findings and penalties under the CWA. In March 2014, the Louisiana District Court ruled that no evidence of Anadarko's alleged culpability or fault could be presented during the penalty phase trial.

The State of Alabama previously brought actions against the Company and other parties for claims arising from the Deepwater Horizon event, including claims for penalties and fines under state environmental laws, which were subsequently dismissed by the Louisiana District Court. The Louisiana District Court has selected this case as its test case for valuing the damages sought by states for claims under federal laws arising from the Deepwater Horizon event. Trial is set for November 2015 and the parties are conducting discovery. The Louisiana District Court's previous rulings apply to Alabama's claims, including the court's decision that only federal law, and not state law, applies; its decision allocating fault and liability among BP and BPAP, Transocean, and Halliburton; and its orders precluding evidence of alleged culpability by Anadarko, leaving only damages to be decided. The Company, pursuant to the Settlement Agreement, is fully indemnified by BP against losses arising as a result of claims for damages.

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17. Contingencies (Continued)

Two separate class-action complaints were filed in June and August 2010, in the New York District Court on behalf of purported purchasers of the Company's stock between June 12, 2009, and June 9, 2010, against Anadarko and certain of its officers. The consolidated action was subsequently transferred to the U.S. District Court for the Southern District of Texas - Houston Division (Texas District Court). The complaints allege causes of action arising pursuant to the Securities Exchange Act of 1934 for purported misstatements and omissions regarding, among other things, the Company's liability related to the Deepwater Horizon events. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. In March 2014, the parties reached a settlement in this matter, which was approved by the Texas District Court in September 2014. The settlement was directly funded by the Company's insurers.

Remaining Liability Outlook It is possible that the Company may recognize additional Deepwater Horizon event-related liabilities for potential fines and penalties and certain other claims not covered by the indemnification provisions of the Settlement Agreement; however, the Company does not believe that any potential liability attributable to the foregoing items, individually or in the aggregate, will have a material impact on the Company's financial condition, results of operations, or cash flows. This assessment takes into account certain qualitative factors, including the subjective and fault-based nature of CWA penalties, the Company's indemnification by BP against certain damage claims as discussed above and BP's creditworthiness.

Although the Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and certain other potential liabilities, the Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c.

The Company will continue to monitor the MDL and other legal proceedings discussed above as well as federal investigations related to the Deepwater Horizon events. The Company cannot predict the nature of additional evidence that may be discovered during the course of legal proceedings or the timing of completion of any legal proceedings.

Deepwater Horizon and Tronox Derivative Claims In May 2013, an Anadarko shareholder filed a derivative action in the 215th District Court of Harris County, Texas (215th District Court) against Anadarko and certain current and former directors and officers (DWH Derivative Action). The shareholder purported to bring claims on behalf of Anadarko and alleged, among other things, that certain current and former directors and officers breached their fiduciary duty in connection with the Company's investment in the Macondo lease.

In addition, in April 2014, the Company's Board of Directors received a letter from a current shareholder demanding that the Board undertake an independent investigation of certain current and former officers and directors for alleged breach of fiduciary duty related to the Company's April 2014 settlement of the Tronox Adversary Proceeding (Tronox Derivative Demand).

In May 2014, the parties reached an agreement to jointly resolve the DWH Derivative Action and the Tronox Derivative Demand in one settlement. In order to achieve the joint settlement, the petition in the DWH Derivative Action was amended to include the allegations asserted in the Tronox Derivative Demand. In August 2014, the 215th District Court approved the settlement. The settlement did not have a material impact on the Company's financial condition, results of operations, or cash flows.

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17. Contingencies (Continued)

Other Litigation In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. Currently, $128 million, the amount of tax originally in dispute, resides in a judicially controlled Brazilian bank account pending final resolution of the matter and is included in other assets on the Company's Consolidated Balance Sheet at December 31, 2014.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. In April 2012, the Company filed simultaneous appeals to the Brazilian Superior Court and the Brazilian Supreme Court. The Brazilian Superior Court and the Brazilian Supreme Court have agreed to hear the case and the Company currently is awaiting the setting of initial hearing dates. In August 2013, following a determination by an administrative court in a related matter that the amount of tax in dispute was not calculated properly, the Company filed a petition requesting the withdrawal of a portion of the judicial deposit to the extent it exceeds $42 million, the amount of tax currently in dispute, and any interest on such amount.

The Company believes that it will more likely than not prevail in Brazilian courts. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2014. The Company continues to vigorously defend its position in Brazilian courts.

Guarantees and Indemnifications The Company provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition. In 2013, as a result of a Chapter 11 bankruptcy declaration by a third party, the DOI ordered Anadarko to perform the decommissioning of a production facility and related wells, which were previously sold to the third party. During 2013, the Company accrued costs of $117 million to decommission the production facility and related wells, reported in other (income) expense, net in the Consolidated Statement of Income. During 2014, the Company recognized a $22 million increase in the estimated decommissioning costs. Anadarko completed decommissioning of the production facility in 2014 and expects to complete decommissioning of the wells in 2015. Decommissioning obligations of $114 million were included in accrued expenses on the Consolidated Balance Sheet at December 31, 2014. Actual costs may vary from this estimate; however, the Company does not believe that any such change will materially impact its financial condition, results of operations, or cash flows.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company's Consolidated Balance Sheets include liabilities for remediation and reclamation obligations of $126 million at December 31, 2014 and December 31, 2013. The current portion of these amounts was included in accounts payable and the long-term portion of these amounts was included in other long-term liabilities-other on the Company's Consolidated Balance Sheets. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

The Company is one of numerous parties previously notified by the California Department of Toxic Substances Control (DTSC) that, as a result of a prior acquisition, it is a potentially responsible party with respect to a landfill located in West Covina, California. While no agreement is in place with the DTSC, the Company recorded a $50 million restoration liability in 2013 with respect to the site, representing the current estimated obligation, which is included in the Company's liability balance at December 31, 2014. The Company could incur additional obligations if any of the potentially responsible parties are ultimately not able to fund their allocated share of the costs or if the DTSC requires a more costly remedial approach. It is possible that the Company's current estimate of probable loss related to this matter could change, perhaps materially, in the future.

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18. Income Taxes

The following summarizes components of income tax expense (benefit) for the years ended December 31:

millions	**2014**	2013	2012
Current			
Federal	**$ 188**	$ 113	$ 45
State	**2**	42	25
Foreign	**1,574**	873	891
	1,764	1,028	961
Deferred			
Federal	**(389)**	94	(30)
State	**27**	(9)	115
Foreign	**215**	52	74
	(147)	137	159
Total income tax expense (benefit)	**$ 1,617**	$ 1,165	$ 1,120

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	**2014**	2013	2012
Income (loss) before income taxes			
Domestic	**$ (3,564)**	$ 428	$ 132
Foreign	**3,618**	1,678	3,433
Total	**$ 54**	$ 2,106	$ 3,565
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ 19**	$ 737	$ 1,248
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	**(11)**	23	93
Tax impact from foreign operations	**62**	204	215
Non-deductible Algerian exceptional profits tax	**193**	144	188
Non-taxable Algeria exceptional profits tax settlement	**-**	13	(679)
Net changes in uncertain tax positions	**1,427**	(29)	28
Deferred tax adjustments	**15**	76	22
Non-deductible Tronox-related contingent loss	**(36)**	36	-
Income attributable to noncontrolling interests	**(66)**	(48)	(24)
Non-deductible Deepwater Horizon settlement	**32**	-	-
Federal manufacturing deduction	**(27)**	-	-
Non-deductible goodwill	**21**	-	15
Other-net	**(12)**	9	14
Total income tax expense (benefit)	**$ 1,617**	$ 1,165	$ 1,120
Effective tax rate	**2,994%**	55%	31%

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18. Income Taxes (Continued)

The following summarizes components of total deferred taxes at December 31:

millions	**2014**	2013
Federal	**$ (7,649)**	$ (8,246)
State, net of federal	**(341)**	(332)
Foreign	**(537)**	(307)
Total deferred taxes	**$ (8,527)**	$ (8,885)

The following summarizes tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) at December 31:

millions	**2014**	2013
Current deferred tax assets	**$ 210**	$ 412
Settlement agreement related to the Tronox Adversary Proceeding	**590**	-
Valuation allowances on deferred tax assets not expected to be realized	**(78)**	(52)
Net current deferred tax assets	**722**	360
Oil and gas exploration and development operations	**(8,418)**	(8,213)
Mineral operations	**(412)**	(410)
Midstream and other depreciable properties	**(1,611)**	(1,586)
Other	**(351)**	(499)
Gross long-term deferred tax liabilities	**(10,792)**	(10,708)
Oil and gas exploration and development costs	**177**	94
Net operating loss carryforward	**558**	599
Foreign tax credit carryforward and alternative minimum tax credit carryforward	**166**	325
Other	**1,428**	1,211
Gross long-term deferred tax assets	**2,329**	2,229
Valuation allowances on deferred tax assets not expected to be realized	**(786)**	(766)
Net long-term deferred tax assets	**1,543**	1,463
Net long-term deferred tax liabilities	**(9,249)**	(9,245)
Total deferred taxes	**$ (8,527)**	$ (8,885)

Changes to valuation allowances, due to changes in judgment regarding the future realizability of deferred tax assets, were an increase of $2 million in 2013 and $23 million in 2012. There were no changes to valuation allowances due to changes in judgment regarding the future realizability of deferred tax assets in 2014.

The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	**2014**	2013	2012
Balance at January 1	**$ (818)**	$ (922)	$ (555)
Additions	**(59)**	(38)	(426)
Reductions	**13**	142	59
Balance at December 31	**$ (864)**	$ (818)	$ (922)

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18. Income Taxes (Continued)

The following summarizes taxes receivable (payable) related to income tax expense (benefit) at December 31:

Balance Sheet Classification	**2014**	2013
Income taxes receivable		
Accounts receivable-other	**$ 93**	$ 66
Other assets	**35**	35
	128	101
Income taxes (payable)		
Accrued expense	**(152)**	(82)
Total net income taxes receivable (payable)	**$ (24)**	$ 19

Tax carryforwards available for use on future income tax returns at December 31, 2014, were as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Net operating loss-foreign	$ -	$ 1,165	2015 - Indefinite
Net operating loss-state	$ 4,477	$ -	2015-2034
Foreign tax credits	$ 167	$ -	2022-2023
Texas margins tax credit	$ 34	$ -	2026

Changes in the balance of unrecognized tax benefits excluding interest and penalties on uncertain tax positions were as follows:

	Assets (Liabilities)		
millions	**2014**	2013	2012
Balance at January 1	**$ (147)**	$ (46)	$ (31)
Increases related to prior-year tax positions	**(11)**	(54)	(17)
Decreases related to prior-year tax positions	**39**	3	3
Increases related to current-year tax positions	**(1,568)**	(72)	(1)
Settlements	**-**	5	-
Lapse of statute of limitations	**-**	17	-
Balance at December 31	**$ (1,687)**	$ (147)	$ (46)

Included in the 2014 ending balance of unrecognized tax benefits presented above are potential benefits of $1.679 billion, of which, if recognized, $1.456 billion would affect the effective tax rate on income, and $188 million would be in the form of tax credits and net operating loss carryforwards that would attract a full valuation allowance. Also included in the 2014 ending balance are benefits of $8 million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain.

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18. Income Taxes (Continued)

In 2013, the Company recognized a deferred tax benefit of $274 million related to the $850 million loss for the Tronox-related contingent liability. In 2014, the Company recognized a deferred tax benefit of $316 million related to the additional $4.360 billion loss for the Tronox-related contingent liability. The total deferred tax benefit of $590 million is net of a $1.326 billion uncertain tax position due to the uncertainty related to the deductibility of the settlement payment. This uncertain tax position is presented in deferred income taxes and as a reduction to the associated deferred tax asset. The Company is a participant in the U.S. Internal Revenue Service's (IRS) Compliance Assurance Process and has regular discussions with the IRS concerning the Company's tax positions. Depending on the outcome of such discussions, it is reasonably possible that the amount of the uncertain tax position related to the settlement could change, perhaps materially. See *Note 17-Contingencies-Tronox Litigation*.

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See *Note 17-Contingencies-Other Litigation*. The Company estimates that $120 million to $130 million of unrecognized tax benefits related to adjustments to taxable income and credits previously recorded pursuant to the accounting standard for accounting for tax uncertainties will reverse within the next 12 months due to expiration of statutes of limitation and audit settlements. Management does not believe that the final resolution of outstanding tax audits and litigation will have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

The Company had accrued approximately $9 million of interest related to uncertain tax positions at December 31, 2014, and $8 million at December 31, 2013. The Company recognized interest and penalties in income tax expense (benefit) of $1 million during 2014 and $(20) million during 2013.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The Company is currently under routine examination by the IRS for the tax years 2008 through 2014.

The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Years
United States	2008-2014
Algeria	2011-2014
Ghana	2006-2014

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19. Supplemental Cash Flow Information

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities for the years ended December 31:

millions	**2014**	2013	2012
Cash paid (received)			
Interest, net of amounts capitalized	**$ 689**	$ 627	$ 684
Income taxes, net of refunds	**956**	169	(300)
Non-cash investing activities			
Fair value of properties and equipment from non-cash transactions	**$ 18**	$ 62	$ 65
Asset retirement cost additions	**348**	297	142
Accruals of property, plant, and equipment	**1,156**	1,446	1,205
Net liabilities assumed or divested in acquisitions and divestitures	**(92)**	(80)	(34)
Non-cash investing and financing activities			
Capital lease obligation	**$ 13**	$ 8	$ -
Floating production, storage, and offloading vessel construction period obligation	**149**	17	-

20. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces natural gas, oil, condensate, and NGLs, and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, natural-gas, and NGLs production, as well as third-party purchased volumes.

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20. Segment Information (Continued)

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Algeria exceptional profits tax settlement, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes exploration expense as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income or cash flows from operating activities. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	**2014**	2013	2012
Income (loss) before income taxes	**$ 54**	$ 2,106	$ 3,565
Exploration expense	**1,639**	1,329	1,946
DD&A	**4,550**	3,927	3,964
Impairments	**836**	794	389
Interest expense	**772**	686	742
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**578**	(307)	443
Deepwater Horizon settlement and related costs	**97**	15	18
Algeria exceptional profits tax settlement	**-**	33	(1,797)
Tronox-related contingent loss	**4,360**	850	(250)
Certain other nonoperating items	**22**	110	-
Less net income attributable to noncontrolling interests	**187**	140	54
Consolidated Adjusted EBITDAX	**$ 12,721**	$ 9,403	$ 8,966

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20. Segment Information (Continued)

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the GAAP definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis, and do not give rise to gain or loss recognition.

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, and net cash from settlement of commodity derivatives. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2014					
Sales revenues	$ 8,603	$ 484	$ 7,288	$ -	$ 16,375
Intersegment revenues	6,225	1,338	(6,771)	(792)	-
Gains (losses) on divestitures and other, net	1,893	(3)	-	205	2,095
Total revenues and other	16,721	1,819	517	(587)	18,470
Operating costs and expenses (1)	4,216	972	740	17	5,945
Net cash from settlement of commodity derivatives	-	-	-	(377)	(377)
Other (income) expense, net (2)	-	-	-	(2)	(2)
Net income attributable to noncontrolling interests	-	187	-	-	187
Total expenses and other	4,216	1,159	740	(362)	5,753
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	-	-	4	-	4
Adjusted EBITDAX	$ 12,505	$ 660	$ (219)	$ (225)	$ 12,721
Net properties and equipment	$ 32,717	$ 6,697	$ -	$ 2,175	$ 41,589
Capital expenditures	$ 7,934	$ 1,149	$ -	$ 173	$ 9,256
Goodwill	$ 5,123	$ 453	$ -	$ -	$ 5,576

(1) Operating costs and expenses excludes exploration expense, DD&A, impairments, Deepwater Horizon settlement and related costs, and Algeria exceptional profits tax settlement since these expenses are excluded from Adjusted EBITDAX.

(2) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

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20. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2013					
Sales revenues	$ 7,090	$ 387	$ 7,390	$ -	$ 14,867
Intersegment revenues	6,405	1,105	(6,859)	(651)	-
Gains (losses) on divestitures and other, net	(622)	(1)	-	337	(286)
Total revenues and other	12,873	1,491	531	(314)	14,581
Operating costs and expenses [1]	3,635	843	652	20	5,150
Net cash from settlement of commodity derivatives	-	-	-	(95)	(95)
Other (income) expense, net [2]	-	-	-	(21)	(21)
Net income attributable to noncontrolling interests	-	140	-	-	140
Total expenses and other	3,635	983	652	(96)	5,174
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	-	-	(4)	-	(4)
Adjusted EBITDAX	$ 9,238	$ 508	$ (125)	$ (218)	$ 9,403
Net properties and equipment	$ 33,409	$ 5,408	$ 9	$ 2,103	$ 40,929
Capital expenditures	$ 7,008	$ 1,248	$ -	$ 267	$ 8,523
Goodwill	$ 5,317	$ 175	$ -	$ -	$ 5,492
2012					
Sales revenues	$ 6,752	$ 325	$ 6,230	$ -	$ 13,307
Intersegment revenues	5,318	959	(5,734)	(543)	-
Gains (losses) on divestitures and other, net	(65)	(8)	-	177	104
Total revenues and other	12,005	1,276	496	(366)	13,411
Operating costs and expenses [1]	3,505	748	616	295	5,164
Net cash from settlement of commodity derivatives	-	-	-	(753)	(753)
Other (income) expense, net	-	-	-	(4)	(4)
Net income attributable to noncontrolling interests	-	54	-	-	54
Total expenses and other	3,505	802	616	(462)	4,461
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	-	-	16	-	16
Adjusted EBITDAX	$ 8,500	$ 474	$ (104)	$ 96	$ 8,966
Net properties and equipment	$ 32,024	$ 4,459	$ 9	$ 1,906	$ 38,398
Capital expenditures	$ 5,906	$ 1,250	$ -	$ 155	$ 7,311
Goodwill	$ 5,317	$ 175	$ -	$ -	$ 5,492

(1) Operating costs and expenses excludes exploration expense, DD&A, impairments, Deepwater Horizon settlement and related costs, and Algeria exceptional profits tax settlement since these expenses are excluded from Adjusted EBITDAX.
(2) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

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20. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area:

	Years Ended December 31,		
millions	**2014**	2013	2012
Sales Revenues			
United States	**$ 13,083**	$ 11,290	$ 9,911
Algeria	**2,435**	2,184	2,182
Other International	**857**	1,393	1,214
Total sales revenues	**$ 16,375**	$ 14,867	$ 13,307

	December 31,	
millions	**2014**	2013
Net Properties and Equipment		
United States	**$ 37,186**	$ 35,486
Algeria	**1,431**	1,582
Other International	**2,972**	3,861
Total net properties and equipment	**$ 41,589**	$ 40,929

Major Customers In 2014, there were no sales to individual customers that exceeded 10% of the Company's total sales revenues. Sales to Total S.A. were $2.0 billion in 2013 and $1.9 billion in 2012. These amounts are included in the oil and gas exploration and production reporting segment.

21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree, and in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is non-contributory.

While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2014, the Company monitors the status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. During 2014, the Company made contributions of $106 million to its funded pension plans, $15 million to its unfunded pension plans, and $15 million to its unfunded other postretirement benefit plans. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute $5 million to its funded pension plans, $24 million to its unfunded pension plans, and $16 million to its unfunded other postretirement benefit plans in 2015.

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2014 and 2013, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2014 and 2013:

	Pension Benefits		Other Benefits	
millions	**2014**	2013	**2014**	2013
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,158**	$ 2,297	**$ 294**	$ 359
Service cost	**99**	85	**7**	9
Interest cost	**99**	78	**15**	14
Actuarial (gain) loss	**337**	(156)	**72**	(74)
Participant contributions	**1**	-	**4**	4
Benefit payments	**(159)**	(149)	**(19)**	(18)
Foreign-currency exchange-rate changes	**(7)**	3	**-**	-
Benefit obligation at end of year (1)	**$ 2,528**	$ 2,158	**$ 373**	$ 294
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,754**	$ 1,462	**$ -**	$ -
Actual return on plan assets	**111**	278	**-**	-
Employer contributions	**121**	160	**15**	14
Participant contributions	**1**	-	**4**	4
Benefit payments	**(159)**	(149)	**(19)**	(18)
Foreign-currency exchange-rate changes	**(10)**	3	**-**	-
Fair value of plan assets at end of year	**$ 1,818**	$ 1,754	**$ -**	$ -
Funded status of the plans at end of year	**$ (710)**	$ (404)	**$ (373)**	$ (294)
Total recognized amounts in the balance sheet consist of				
Other assets	**$ 41**	$ 37	**$ -**	$ -
Accrued expenses	**(24)**	(19)	**(15)**	(15)
Other long-term liabilities-other	**(727)**	(422)	**(358)**	(279)
Total	**$ (710)**	$ (404)	**$ (373)**	$ (294)
Total recognized amounts in accumulated other comprehensive income consist of				
Prior service cost (credit)	**$ (1)**	$ (1)	**$ 2**	$ 2
Net actuarial (gain) loss	**740**	441	**1**	(78)
Total	**$ 739**	$ 440	**$ 3**	$ (76)

(1) The accumulated benefit obligation for all defined-benefit pension plans was $2.1 billion at December 31, 2014, and $1.8 billion at December 31, 2013.

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following summarizes the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

millions	**2014**	2013
Projected benefit obligation	**$ 2,403**	$ 2,047
Accumulated benefit obligation	**2,024**	1,742
Fair value of plan assets	**1,652**	1,606

The following summarizes the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			Other Benefits		
millions	**2014**	2013	2012	**2014**	2013	2012
Components of net periodic benefit cost						
Service cost	**$ 99**	$ 85	$ 76	**$ 7**	$ 9	$ 9
Interest cost	**99**	78	85	**15**	14	16
Expected return on plan assets	**(106)**	(91)	(91)	**-**	-	-
Amortization of net actuarial loss (gain)	**34**	118	93	**(7)**	-	-
Amortization of net prior service cost (credit)	**-**	-	-	**-**	1	2
Settlement loss	**-**	14	-	**-**	-	-
Net periodic benefit cost	**$ 126**	$ 204	$ 163	**$ 15**	$ 24	$ 27
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ (333)**	$ 342	$ (156)	**$ (72)**	$ 74	$ 1
Amortization of net actuarial (gain) loss	**34**	118	93	**(7)**	-	-
Amortization of net prior service cost (credit)	**-**	-	-	**-**	1	2
Settlement loss	**-**	14	-	**-**	-	-
Total amounts recognized in other comprehensive income (expense)	**$ (299)**	$ 474	$ (63)	**$ (79)**	$ 75	$ 3

In 2015, an estimated $49 million of net actuarial loss for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations at December 31:

	Pension Benefits		Other Benefits	
	2014	2013	**2014**	2013
Discount rate	**4.00%**	4.75%	**4.25%**	5.25%
Rates of increase in compensation levels	**5.25%**	5.00%	**5.25%**	5.25%

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high-quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. Assumed rates of compensation increases for active participants vary by age group, with the resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

The following summarizes the weighted-average assumptions used by the Company in determining the net periodic pension and other postretirement benefit cost:

	Pension Benefits			Other Benefits		
	2014	2013	2012	**2014**	2013	2012
Discount rate	**4.75%**	3.50%	4.50%	**5.25%**	4.00%	4.75%
Long-term rate of return on plan assets	**6.75%**	7.00%	7.00%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.00%**	4.50%	4.50%	**5.25%**	4.50%	4.50%

At December 31, 2014 and December 31, 2013, an 8.00% annual rate of increase in the per-capita cost of covered health care benefits for the next year was assumed for purposes of measuring other postretirement benefit obligations. This rate is expected to gradually decrease to 5.00% in 2020 and beyond. The assumed health care cost trend rate can have a significant effect on the cost and obligation amounts reported for the health care plan. A 1% change in the assumed health care cost trend rate over the projected period would have the following effects:

millions	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 3	$ (2)
Effect on other postretirement benefit obligation	$ 40	$ (33)

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 45%-55% equity securities, 20%-30% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' collective fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2014 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach, while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are derived from their relationship to the equity and fixed-income markets.

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The fair value of the Company's pension plan assets by asset class and input level within the fair-value hierarchy were as follows:

millions

December 31, 2014	Level 1	Level 2	Level 3	Total
Investments				
Cash and cash equivalents	$ 3	$ 53	$ -	$ 56
Fixed income				
Mortgage-backed securities	-	51	-	51
U.S. government securities	-	56	-	56
Other fixed-income securities (1)	48	212	-	260
Equity securities				
Domestic	446	130	-	576
International	124	299	-	423
Other				
Real estate	-	56	94	150
Private equity	-	-	84	84
Hedge funds and other alternative strategies	9	-	126	135
Other	$ -	$ 30	$ -	$ 30
Total investments (2)	$ 630	$ 887	$ 304	$ 1,821
Liabilities				
Hedge funds and other alternative strategies	$ (3)	$ -	$ -	$ (3)
Total liabilities	$ (3)	$ -	$ -	$ (3)
December 31, 2013				
Investments				
Cash and cash equivalents	$ 17	$ 80	$ -	$ 97
Fixed income				
Mortgage-backed securities	-	54	-	54
U.S. government securities	-	52	-	52
Other fixed-income securities (1)	42	197	-	239
Equity securities				
Domestic	445	116	-	561
International	148	303	-	451
Other				
Real estate	-	47	86	133
Private equity	-	-	72	72
Hedge funds and other alternative strategies	31	-	79	110
Total investments (2)	$ 683	$ 849	$ 237	$ 1,769
Liabilities				
Hedge funds and other alternative strategies	$ (17)	$ -	$ -	$ (17)
Total liabilities	$ (17)	$ -	$ -	$ (17)

(1) Amounts include investments in diversified fixed-income collective investment funds with exposure to mortgage-backed securities, government-issued securities, corporate debt, and other fixed-income securities.
(2) Amount excludes receivables and payables, primarily related to Level 1 investments.

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities, as well as shares of open-end mutual funds or similar investment vehicles that do not have a readily determinable fair value, but are valued at the net asset value per share (NAV). For such funds, the NAV is the value at which investors transact with the fund, and is determined by the fund based on the estimated fair values of the underlying fund assets. Fair value of investments included as Level 3 inputs generally also reflect investments valued at fund NAVs, but, unlike investments characteristic of Level 2 fair-value measurements, such plan assets have significant liquidity restrictions or other features that are not reflected in NAV.

The following summarizes changes in the fair value of investments based on Level 3 inputs:

millions	Hedge Funds and Other Alternative Strategies	Private Equity	Real Estate	Total
Balance at January 1, 2013	$ 77	$ 64	$ 78	$ 219
Acquisitions (dispositions), net	(6)	-	2	(4)
Actual return on plan assets				
Relating to assets sold during the reporting period	1	4	-	5
Relating to assets still held at the reporting date	7	4	6	17
Balance at December 31, 2013	$ 79	$ 72	$ 86	$ 237
Acquisitions (dispositions), net	**42**	**-**	**2**	**44**
Actual return on plan assets				
Relating to assets sold during the reporting period	**2**	**5**	**-**	**7**
Relating to assets still held at the reporting date	**3**	**7**	**6**	**16**
Balance at December 31, 2014	**$ 126**	**$ 84**	**$ 94**	**$ 304**

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks, such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows, such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate values, delinquencies or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

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21. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Expected Benefit Payments

The following summarizes estimated benefit payments for the next ten years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2015	$ 162	$ 16
2016	175	17
2017	199	18
2018	194	18
2019	216	19
2020-2024	1,192	109

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, the most significant of which is the Anadarko Employee Savings Plan (ESP). All regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense of $76 million for 2014, $78 million for 2013, and $55 million for 2012, related to these plans.

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The unaudited supplemental information on oil and gas exploration and production activities for 2014, 2013, and 2012 has been presented in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 932, *Extractive Activities-Oil and Gas* and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria and Ghana. The Company sold its Chinese subsidiary during 2014.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and proved undeveloped reserves, net of third-party royalty interests, of natural gas, oil, condensate, and natural-gas liquids (NGLs) owned at each year end and changes in proved reserves during each of the last three years. Natural-gas volumes are presented in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate, and NGLs are presented in millions of barrels (MMBbls). Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes.

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and governmental restrictions.

Prices used to compute the information presented in the following tables are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were $4.35, $3.67, and $2.76 per MMBtu of natural gas and $94.99, $96.78, and $94.71 per barrel of oil for 2014, 2013, and 2012. The benchmark price for NGLs used in the computation, previously the same as that for oil, was converted to a NGLs-specific price of $45.25 per barrel in 2014.

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
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Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)			Oil and Condensate (MMBbls)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2011	8,365	-	8,365	536	235	771
Revisions of prior estimates	635	-	635	62	52	114
Extensions, discoveries, and other additions	418	-	418	9	-	9
Purchases in place	26	-	26	-	-	-
Sales in place	(199)	-	(199)	(42)	-	(42)
Production	(916)	-	(916)	(54)	(31)	(85)
December 31, 2012	8,329	-	8,329	511	256	767
Revisions of prior estimates	1,276	-	1,276	96	21	117
Extensions, discoveries, and other additions	416	-	416	52	14	66
Purchases in place	153	-	153	1	-	1
Sales in place	(4)	-	(4)	(10)	-	(10)
Production	(965)	-	(965)	(58)	(32)	(90)
December 31, 2013	**9,205**	**-**	**9,205**	**592**	**259**	**851**
Revisions of prior estimates	**710**	**31**	**741**	**167**	**18**	**185**
Extensions, discoveries, and other additions	**196**	**-**	**196**	**25**	**-**	**25**
Purchases in place	**-**	**-**	**-**	**-**	**-**	**-**
Sales in place	**(492)**	**-**	**(492)**	**(6)**	**(17)**	**(23)**
Production	**(951)**	**-**	**(951)**	**(74)**	**(35)**	**(109)**
December 31, 2014	**8,668**	**31**	**8,699**	**704**	**225**	**929**
Proved Developed Reserves						
December 31, 2011	6,113	-	6,113	352	173	525
December 31, 2012	6,445	-	6,445	318	208	526
December 31, 2013	7,120	-	7,120	347	202	549
December 31, 2014	**6,635**	**27**	**6,662**	**352**	**190**	**542**
Proved Undeveloped Reserves						
December 31, 2011	2,252	-	2,252	184	62	246
December 31, 2012	1,884	-	1,884	193	48	241
December 31, 2013	2,085	-	2,085	245	57	302
December 31, 2014	**2,033**	**4**	**2,037**	**352**	**35**	**387**

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**ANADARKO PETROLEUM CORPORATION
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Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	**International**	**Total**	**United States**	**International**	**Total**
Proved Reserves						
December 31, 2011	361	13	374	2,291	248	2,539
Revisions of prior estimates (1)	65	(1)	64	233	51	284
Extensions, discoveries, and other additions	3	-	3	82	-	82
Purchases in place	-	-	-	4	-	4
Sales in place	(6)	-	(6)	(81)	-	(81)
Production	(30)	-	(30)	(237)	(31)	(268)
December 31, 2012	393	12	405	2,292	268	2,560
Revisions of prior estimates (1)	17	-	17	326	21	347
Extensions, discoveries, and other additions	10	-	10	131	14	145
Purchases in place	9	-	9	36	-	36
Sales in place	(1)	-	(1)	(12)	-	(12)
Production	(33)	-	(33)	(252)	(32)	(284)
December 31, 2013	**395**	**12**	**407**	**2,521**	**271**	**2,792**
Revisions of prior estimates (1)	**129**	**2**	**131**	**414**	**25**	**439**
Extensions, discoveries, and other additions	**5**	**-**	**5**	**63**	**-**	**63**
Purchases in place	**-**	**-**	**-**	**-**	**-**	**-**
Sales in place	**(19)**	**-**	**(19)**	**(107)**	**(17)**	**(124)**
Production	**(44)**	**(1)**	**(45)**	**(276)**	**(36)**	**(312)**
December 31, 2014	**466**	**13**	**479**	**2,615**	**243**	**2,858**
Proved Developed Reserves						
December 31, 2011	267	-	267	1,638	173	1,811
December 31, 2012	283	-	283	1,675	208	1,883
December 31, 2013	268	-	268	1,801	202	2,003
December 31, 2014	**304**	**13**	**317**	**1,762**	**207**	**1,969**
Proved Undeveloped Reserves						
December 31, 2011	94	13	107	653	75	728
December 31, 2012	110	12	122	617	60	677
December 31, 2013	127	12	139	720	69	789
December 31, 2014	**162**	**-**	**162**	**853**	**36**	**889**

(1) Revisions of prior estimates include additions generated by Anadarko's infill drilling programs of 577 MMBOE for 2014, 410 MMBOE for 2013, and 383 MMBOE for 2012.

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In 2014, Anadarko added 63 MMBOE of proved reserves through extensions and discoveries primarily as a result of successful drilling in the Marcellus and Wolfcamp shale plays. Although shale plays represented only about 17% of the Company's total proved reserves at December 31, 2014, growth in the shale plays contributed 49 MMBOE, or 78%, of the total extensions and discoveries. Total revisions include the effects of new infill drilling, changes in commodity prices and other updates reflecting changes in economic conditions, changes in reservoir performance, and changes to development plans. Total revisions in 2014 resulted in an increase of 439 MMBOE, or 16%, of the beginning-of-year reserves base. These revisions are primarily associated with a 577 MMBOE increase related to successful infill drilling in large onshore areas such as the Wattenberg area and the Eagleford and Haynesville shales. Partially offsetting these positive infill revisions was a net decrease of 138 MMBOE, primarily associated with the optimization of horizontal drilling locations and the discontinuation of vertical well workover plans in the Wattenberg area. In 2014, the Company sold properties or interests in properties containing 69 MMBOE of proved developed reserves and 55 MMBOE of proved undeveloped reserves. Sales included the divestiture of the Company's interest in the Pinedale/Jonah assets in Wyoming, the Company's Chinese subsidiary, and a portion of the Company's working interest in the East Texas Chalk area.

In 2013, Anadarko added 145 MMBOE of proved reserves through extensions and discoveries as the result of successful drilling primarily in the Marcellus shale and the Gulf of Mexico. Although shale plays represented only about 13% of the Company's total proved reserves at December 31, 2013, growth in the shale plays contributed 70 MMBOE, or 48%, of the total extensions and discoveries. Total revisions in 2013 resulted in an increase of 347 MMBOE, or 14%, of the beginning-of-year reserves base. Total 2013 revisions included an increase of 410 MMBOE related to successful infill drilling, primarily in large onshore areas such as Wattenberg, Greater Natural Buttes, and the Eagleford shale, and 30 MMBOE resulting from improved oil and natural-gas prices. Partially offsetting these positive revisions were decreases of 53 MMBbls of NGLs reserves due to lower ethane prices and 40 MMBOE due to other non-price-related revisions primarily in the Rocky Mountains Region (Rockies). In 2013, the Company sold U.S. properties or interests in U.S. properties containing 12 MMBOE of proved undeveloped reserves. Sales were almost exclusively associated with a partial sale of a working interest in the Gulf of Mexico Heidelberg development project. Acquisitions of proved reserves were 36 MMBOE, related to domestic assets almost exclusively in the Rockies.

In 2012, Anadarko added 82 MMBOE of proved reserves through extensions and discoveries as the result of successful drilling in the Marcellus shale and the Gulf of Mexico. Shale plays contributed 66 MMBOE of the total extensions and discoveries in 2012. Total revisions in 2012 were 284 MMBOE or 11% of the beginning-of-year reserves base. Total 2012 revisions included an increase of 383 MMBOE related to successful infill drilling, primarily in Greater Natural Buttes, Wattenberg, and Carthage, and 33 MMBOE resulting from the resolution of the Algeria exceptional profits tax dispute. Partially offsetting these positive revisions were decreases of 68 MMBOE due to lower commodity prices, 56 MMBOE at Wattenberg primarily due to removing reserves associated with the discontinued vertical drilling program, and 8 MMBOE from all other assets. In 2012, the Company sold U.S. properties or interests in U.S. properties containing 81 MMBOE of proved reserves, including 59 MMBOE of proved developed reserves and 22 MMBOE of proved undeveloped reserves. Sales included a portion of the Company's working interests in the Rockies Salt Creek enhanced oil recovery project and the Gulf of Mexico Lucius development project, and asset divestitures in South Texas, West Texas, the Gulf of Mexico, the Rockies, and North Louisiana.

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Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's midstream and marketing reporting segments, liquefied natural gas (LNG) facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2014			
Capitalized			
Unproved properties	**$ 3,858**	**$ 1,291**	**$ 5,149**
Proved properties	**53,545**	**4,895**	**58,440**
	57,403	**6,186**	**63,589**
Less accumulated DD&A	**29,055**	**1,902**	**30,957**
Net capitalized costs	**$ 28,348**	**$ 4,284**	**$ 32,632**
December 31, 2013			
Capitalized			
Unproved properties	$ 4,938	$ 1,970	$ 6,908
Proved properties	48,631	5,540	54,171
	53,569	7,510	61,079
Less accumulated DD&A	25,560	2,333	27,893
Net capitalized costs	$ 28,009	$ 5,177	$ 33,186

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2014			
Property acquisitions			
Unproved	**$ 264**	**$ 19**	**$ 283**
Proved	**3**	**-**	**3**
Exploration	**1,095**	**616**	**1,711**
Development	**6,158**	**557**	**6,715**
Total costs incurred	**$ 7,520**	**$ 1,192**	**$ 8,712**
Year Ended December 31, 2013			
Property acquisitions			
Unproved	$ 282	$ 45	$ 327
Proved	324	-	324
Exploration	1,031	939	1,970
Development	4,421	444	4,865
Total costs incurred	$ 6,058	$ 1,428	$ 7,486
Year Ended December 31, 2012			
Property acquisitions			
Unproved	$ 224	$ 15	$ 239
Proved	-	-	-
Exploration	1,064	1,000	2,064
Development	3,592	472	4,064
Total costs incurred	$ 4,880	$ 1,487	$ 6,367

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
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Results of Operations

Results of operations for producing activities consist of all activities within the oil and gas exploration and production reporting segment. Net revenues from production include only the revenues from the production and sale of natural gas, oil, condensate, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities used in oil and gas operations, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related general and administrative costs. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Algeria exceptional profits tax settlement represents the Company's resolution of the Algeria exceptional profits tax dispute with Sonatrach, which provided for the transfer of $1.7 billion of oil to the Company over a 12-month period ending in mid-2013. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion, and amortization allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	United States	International	Total
Year Ended December 31, 2014			
Net revenues from production			
Third-party sales	$ 7,425	$ 1,518	$ 8,943
Sales to consolidated affiliates	4,453	1,773	6,226
Gains (losses) on property dispositions	(91)	1,982	1,891
	11,787	5,273	17,060
Production costs			
Oil and gas operating	968	203	1,171
Oil and gas transportation and other	1,150	33	1,183
Production-related general and administrative expenses	394	32	426
Other taxes	652	535	1,187
	3,164	803	3,967
Exploration expenses	1,218	421	1,639
Depreciation, depletion, and amortization	3,783	398	4,181
Impairments related to oil and gas properties	821	-	821
Deepwater Horizon settlement and related costs	97	-	97
	2,704	3,651	6,355
Income tax expense	995	979	1,974
Results of operations	$ 1,709	$ 2,672	$ 4,381

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Results of Operations (Continued)

millions	United States	International	Total
Year Ended December 31, 2013			
Net revenues from production			
Third-party sales	$ 6,567	$ 856	$ 7,423
Sales to consolidated affiliates	3,685	2,720	6,405
Gains (losses) on property dispositions	(618)	(3)	(621)
	9,634	3,573	13,207
Production costs			
Oil and gas operating	874	218	1,092
Oil and gas transportation and other	998	22	1,020
Production-related general and administrative expenses	332	5	337
Other taxes	569	455	1,024
	2,773	700	3,473
Exploration expenses	611	718	1,329
Depreciation, depletion, and amortization	3,222	399	3,621
Impairments related to oil and gas properties	704	-	704
Algeria exceptional profits tax settlement	-	33	33
Deepwater Horizon settlement and related costs	15	-	15
	2,309	1,723	4,032
Income tax expense	845	1,005	1,850
Results of operations	$ 1,464	$ 718	$ 2,182
Year Ended December 31, 2012			
Net revenues from production			
Third-party sales	$ 6,233	$ 846	$ 7,079
Sales to consolidated affiliates	2,767	2,550	5,317
Gains (losses) on property dispositions	(16)	(48)	(64)
	8,984	3,348	12,332
Production costs			
Oil and gas operating	786	190	976
Oil and gas transportation and other	931	22	953
Production-related general and administrative expenses	318	18	336
Other taxes	581	599	1,180
	2,616	829	3,445
Exploration expenses	1,484	462	1,946
Depreciation, depletion and amortization	3,320	390	3,710
Impairments related to oil and gas properties	364	-	364
Algeria exceptional profits tax settlement	-	(1,797)	(1,797)
Deepwater Horizon settlement and related costs	18	-	18
	1,182	3,464	4,646
Income tax expense	433	943	1,376
Results of operations	$ 749	$ 2,521	$ 3,270

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future net cash flows from proved reserves of natural gas, oil, condensate, and NGLs for 2014, 2013, and 2012 are computed based on the average beginning-of-the-month prices during the 12-month period for the respective year. Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were $4.35, $3.67, and $2.76 per MMBtu of natural gas and $94.99, $96.78, and $94.71 per barrel of oil, for 2014, 2013, and 2012. The benchmark price for NGLs used in the computation, previously the same as that for oil, was converted to a NGLs-specific price of $45.25 per barrel in 2014. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by U.S. Generally Accepted Accounting Principles.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserves volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
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(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
December 31, 2014			
Future cash inflows	**$ 114,384**	**$ 23,795**	**$ 138,179**
Future production costs	**36,390**	**6,061**	**42,451**
Future development costs	**14,794**	**1,356**	**16,150**
Future income tax expenses	**21,813**	**6,968**	**28,781**
Future net cash flows	**41,387**	**9,410**	**50,797**
10% annual discount for estimated timing of cash flows	**17,239**	**2,898**	**20,137**
Standardized measure of discounted future net cash flows	**$ 24,148**	**$ 6,512**	**$ 30,660**
December 31, 2013			
Future cash inflows	$ 102,765	$ 28,454	$ 131,219
Future production costs	33,271	6,819	40,090
Future development costs	12,285	1,501	13,786
Future income tax expenses	20,222	8,148	28,370
Future net cash flows	36,987	11,986	48,973
10% annual discount for estimated timing of cash flows	15,818	4,049	19,867
Standardized measure of discounted future net cash flows	$ 21,169	$ 7,937	$ 29,106
December 31, 2012			
Future cash inflows	$ 86,129	$ 29,268	$ 115,397
Future production costs	29,356	6,239	35,595
Future development costs	9,195	606	9,801
Future income tax expenses	16,804	9,035	25,839
Future net cash flows	30,774	13,388	44,162
10% annual discount for estimated timing of cash flows	13,236	4,612	17,848
Standardized measure of discounted future net cash flows	$ 17,538	$ 8,776	$ 26,314

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ANADARKO PETROLEUM CORPORATION
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Changes in Standardized Measure of Discounted Future Net Cash Flows
Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2014			
Balance at January 1	**$ 21,169**	**$ 7,937**	**$ 29,106**
Sales and transfers of oil and gas produced, net of production costs	**(8,714)**	**(2,492)**	**(11,206)**
Net changes in prices and production costs	**(4,046)**	**(1,984)**	**(6,030)**
Changes in estimated future development costs	**(4,180)**	**(250)**	**(4,430)**
Extensions, discoveries, additions, and improved recovery, less related costs	**963**	**-**	**963**
Development costs incurred during the period	**2,591**	**279**	**2,870**
Revisions of previous quantity estimates	**13,703**	**1,921**	**15,624**
Purchases of minerals in place	**-**	**-**	**-**
Sales of minerals in place	**(591)**	**(696)**	**(1,287)**
Accretion of discount	**3,221**	**1,341**	**4,562**
Net change in income taxes	**(1,294)**	**549**	**(745)**
Other	**1,326**	**(93)**	**1,233**
Balance at December 31	**$ 24,148**	**$ 6,512**	**$ 30,660**
2013			
Balance at January 1	$ 17,538	$ 8,776	$ 26,314
Sales and transfers of oil and gas produced, net of production costs	(7,478)	(2,881)	(10,359)
Net changes in prices and production costs	1,394	(1,072)	322
Changes in estimated future development costs	(2,326)	(193)	(2,519)
Extensions, discoveries, additions, and improved recovery, less related costs	2,659	(128)	2,531
Development costs incurred during the period	1,076	193	1,269
Revisions of previous quantity estimates	6,526	1,324	7,850
Purchases of minerals in place	253	-	253
Sales of minerals in place	284	-	284
Accretion of discount	2,671	1,465	4,136
Net change in income taxes	(1,865)	401	(1,464)
Other	437	52	489
Balance at December 31	$ 21,169	$ 7,937	$ 29,106

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
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Changes in Standardized Measure of Discounted Future Net Cash Flows
Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2012			
Balance at January 1	$ 20,173	$ 6,283	$ 26,456
Sales and transfers of oil and gas produced, net of production costs	(6,384)	(2,571)	(8,955)
Net changes in prices and production costs	(7,948)	(391)	(8,339)
Changes in estimated future development costs	(744)	(70)	(814)
Extensions, discoveries, additions, and improved recovery, less related costs	963	-	963
Development costs incurred during the period	1,103	357	1,460
Revisions of previous quantity estimates	5,026	4,390	9,416
Purchases of minerals in place	(9)	-	(9)
Sales of minerals in place	(763)	-	(763)
Accretion of discount	3,063	1,139	4,202
Net change in income taxes	1,285	(759)	526
Other	1,773	398	2,171
Balance at December 31	$ 17,538	$ 8,776	$ 26,314

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ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following summarizes quarterly financial data for 2014 and 2013:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2014				
Sales revenues	**$ 4,338**	**$ 4,385**	**$ 4,230**	**$ 3,422**
Gains (losses) on divestitures and other, net	**1,506**	**54**	**780**	**(245)**
Deepwater Horizon settlement and related costs	**-**	**93**	**3**	**1**
Operating income (loss)	**2,975**	**1,209**	**1,698**	**(479)**
Tronox-related contingent loss	**4,300**	**19**	**19**	**22**
Net income (loss)	**(2,626)**	**266**	**1,147**	**(350)**
Net income (loss) attributable to noncontrolling interests	**43**	**39**	**60**	**45**
Net income (loss) attributable to common stockholders	**(2,669)**	**227**	**1,087**	**(395)**
Earnings per share				
Net income (loss) attributable to common stockholders-basic	**$ (5.30)**	**$ 0.45**	**$ 2.13**	**$ (0.78)**
Net income (loss) attributable to common stockholders-diluted	**$ (5.30)**	**$ 0.45**	**$ 2.12**	**$ (0.78)**
Average number common shares outstanding-basic	**504**	**505**	**506**	**507**
Average number common shares outstanding-diluted	**504**	**507**	**508**	**507**
2013				
Sales revenues	$ 3,718	$ 3,440	$ 3,789	$ 3,920
Gains (losses) on divestitures and other, net	175	57	64	(582)
Algeria exceptional profits tax settlement	33	-	-	-
Deepwater Horizon settlement and related costs	3	4	5	3
Operating income (loss)	1,289	1,140	689	215
Tronox-related contingent loss	-	-	-	850
Net income (loss)	484	959	223	(725)
Net income attributable to noncontrolling interests	24	30	41	45
Net income (loss) attributable to common stockholders	460	929	182	(770)
Earnings per share				
Net income (loss) attributable to common stockholders-basic	$ 0.91	$ 1.84	$ 0.36	$ (1.53)
Net income (loss) attributable to common stockholders-diluted	$ 0.91	$ 1.83	$ 0.36	$ (1.53)
Average number common shares outstanding-basic	501	502	503	504
Average number common shares outstanding-diluted	503	504	505	504

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by the Company in reports that it files under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2014.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2014 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance-Committees of the Board, Corporate Governance-Board of Directors,* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Anadarko Petroleum Corporation Proxy Statement (Proxy Statement), for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 12, 2015 (to be filed with the Securities and Exchange Commission prior to April 2, 2015), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/Responsibility/Good-Governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance-Board of Directors-Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance-Board of Directors-Director Compensation, Corporate Governance-Director Compensation Table for 2014, Compensation and Benefits Committee Report on 2014 Executive Compensation, Compensation Discussion and Analysis,* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement and *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, which are incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See *Corporate Governance-Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this report or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this report, page 84.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or double asterisk (**) and are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

Exhibit Number	Description
2 (i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation, filed as Exhibit 2.2 to Form 8-K filed on June 26, 2006
3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of November 6, 2014, filed as Exhibit 3.1 to Form 8-K filed on November 10, 2014
4 (i)	Trustee Indenture dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on September 19, 2006
(ii)	Second Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.1 to Form 8-K filed on October 6, 2006
(iii)	Ninth Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.2 to Form 8-K filed on October 6, 2006
(iv)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019, filed as Exhibit 4.1 to Form 8-K filed on March 6, 2009
(v)	Form of 7.625% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on March 6, 2009
(vi)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009
(vii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039, filed as Exhibit 4.1 to Form 8-K filed on June 12, 2009
(viii)	Form of 5.75% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on June 12, 2009
(ix)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009
(x)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009
(xi)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040, filed as Exhibit 4.1 to Form 8-K filed on March 16, 2010
(xii)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010
(xiii)	Officers' Certificate of Anadarko Petroleum Corporation dated August 9, 2010, establishing the 6.375% Senior Notes due 2017, filed as Exhibit 4.1 to Form 8-K filed on August 12, 2010

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	Exhibit Number	Description
	4 (xiv)	Form of 6.375% Senior Notes due 2017, filed as Exhibit 4.2 to Form 8-K filed on August 12, 2010
	(xv)	Officers' Certificate of Anadarko Petroleum Corporation dated July 7, 2014, establishing the 3.45% Senior Notes due 2024 and the 4.50% Senior Notes due 2044, filed as Exhibit 4.1 to Form 8-K filed on July 7, 2014
	(xvi)	Form of 3.45% Senior Notes due 2024, filed as Exhibit 4.2 to Form 8-K filed on July 7, 2014
	(xvii)	Form of 4.50% Senior Notes due 2044, filed as Exhibit 4.3 to Form 8-K filed on July 7, 2014
†	10 (i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998, filed as Appendix A to DEF 14A filed on March 16, 1998
†	(ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 17, 2005
†	(iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan, filed as Appendix A to DEF 14A filed on March 18, 2005
†	(iv)	Form of Anadarko Petroleum Corporation Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 17, 2005
†	(v)	Form of Anadarko Petroleum Corporation Non-Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 17, 2005
†	(vi)	Form of Stock Option Agreement-1999 Stock Incentive Plan (UK Nationals), filed as Exhibit 10.4 to Form 8-K filed on November 17, 2005
†	(vii)	Amendment to Stock Option Agreement Under the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10.1 to Form 8-K filed on January 23, 2007
†	(viii)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan (Amendment to Performance Unit Agreement), filed as Exhibit 10.3 to Form 8-K filed on November 13, 2007
†	(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 1999, filed on March 16, 2000
†	(x)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Unit Award Letter, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2007
†	(xi)	The Approved UK Sub-Plan of the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xii)	Key Employee Change of Control Contract, filed as Exhibit 10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998
†	(xiii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000
†	(xiv)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003
†	(xv)	Form of Key Employee Change of Control Contract (2011), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011
†	(xvi)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004-Robert J. Allison, Jr., filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xvii)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010

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	Exhibit Number	Description
†*	10 (xviii)	First Amendment, dated July 1, 2010, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007)
†*	(xix)	Second Amendment, dated November 30, 2011, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007)
†*	(xx)	Third Amendment, dated December 18, 2014, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007)
†	(xxi)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007), filed as Exhibit 10.2 to Form 8-K filed on November 13, 2007
†*	(xxii)	First Amendment, dated November 30, 2011, to the Anadarko Retirement Restoration Plan (As Amended and Restated Effective January 1, 2007)
†	(xxiii)	Anadarko Petroleum Corporation Estate Enhancement Program, filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxiv)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives, filed as Exhibit 10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxv)	Estate Enhancement Program Agreements effective November 29, 2000, filed as Exhibit 10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001
†	(xxvi)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002, filed as Exhibit 10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003
†	(xxvii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003, filed as Exhibit 10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xxviii)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008, filed as Exhibit 10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xxix)	Anadarko Petroleum Corporation Officer Severance Plan, filed as Exhibit 10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xxx)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10(b)(v) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xxxi)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004
	(xxxii)	$5,000,000,000 Revolving Credit Agreement, dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB NorBank ASA, The Royal Bank of Scotland plc, Société Général, and Wells Fargo Bank, N.A., as Syndication Agents, and the several lenders named therein, filed as Exhibit 10.1 to Form 8-K filed on September 8, 2010
	(xxxiii)	First Amendment to Revolving Credit Agreement, dated as of August 3, 2011, to the Revolving Credit Agreement dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A. as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2011, filed on October 31, 2011

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	Exhibit Number	Description
	10 (xxxiv)	Second Amendment to Revolving Credit Agreement, dated as of March 26, 2014, to the Revolving Credit Agreement dated as of September 2, 2010, as amended on August 3, 2011, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto, filed as Exhibit 10(ii) to Form 10-Q for quarter ended March 31, 2014, filed on May 5, 2014
†	(xxxv)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.1 to Form 8-K filed on May 27, 2008
†	(xxxvi)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 13, 2009
†	(xxxvii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2009
†	(xxxviii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 13, 2009
†	(xxxvix)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.2 to Form 8-K filed on May 27, 2008
†	(xl)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.3 to Form 8-K filed on May 27, 2008
†	(xli)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan (2013), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2013, filed on July 29, 2013
†	(xlii)	Anadarko Petroleum Corporation Benefits Trust Agreement, amended and restated effective as of November 5, 2008, filed as Exhibit 10(lvi) to Form 10-K for year ended December 31, 2008, filed on February 25, 2009
†	(xliii)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(i) to Form 10-Q for the quarter ended June 30, 2014, filed on July 29, 2014
†	(xliv)	First Amendment, dated December 17, 2013, to the Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(ii) to Form 10-Q for the quarter ended June 30, 2014, filed on July 29, 2014
	(xlv)	Operating Agreement, dated October 1, 2009, between BP Exploration & Production Inc., as Operator, and MOEX Offshore 2007 LLC, as Non-Operator, as ratified by that certain Ratification and Joinder of Operating Agreement, dated December 17, 2009, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation (as Non-Operator), Anadarko E&P Company LP (as predecessor in interest to Anadarko Petroleum Corporation), and MOEX Offshore 2007 LLC, together with material exhibits, filed as Exhibit 10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010
	(xlvi)	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated October 16, 2011, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation, Anadarko E&P Company LP, BP Corporation North America Inc. and BP p.l.c., filed as Exhibit 10(xlii) to Form 10-K for year ended December 31, 2011, filed on February 21, 2012 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment)
†	(xlvii)	Severance Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.2 to Form 8-K filed on February 21, 2012
†	(xlviii)	Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated May 15, 2012, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2012, filed on August 8, 2012

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	Exhibit Number	Description
†	10 (xlix)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, effective as of May 15, 2012, filed as Exhibit 10.1 to Form 8-K filed on May 15, 2012
†	(l)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on May 15, 2012
†	(li)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on May 15, 2012
†	(lii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.4 to Form 8-K filed on May 15, 2012
†	(liii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 9, 2012
†	(liv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 9, 2012
†	(lv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement (2014), filed as Exhibit 10.1 to Form 8-K filed on November 10, 2014
†	(lvi)	Form of U.K. Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.5 to Form 8-K filed on May 15, 2012
†	(lvii)	Amended and Restated Performance Unit Award Agreement, effective November 5, 2012, for R. A. Walker, filed as Exhibit 10.3 to Form 8-K filed on November 9, 2012
	(lviii)	Settlement Agreement dated as of April 3, 2014, by and among (1) the Anadarko Litigation Trust, (2) the United States of America in its capacity as plaintiff-intervenor in the Tronox Adversary Proceeding and acting for and on behalf of certain U.S. government agencies and (3) Anadarko Petroleum Corporation, Kerr-McGee Corporation, and certain other subsidiaries, filed as exhibit 10.1 to Form 8-K filed on April 3, 2014
	(lix)	Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on June 23, 2014
	(lx)	First Amendment to Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on November 19, 2014
	(lxi)	364-Day Revolving Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on June 23, 2014
	(lxii)	First Amendment to 364-Day Revolving Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on November 19, 2014
*	12	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends
*	21	List of Subsidiaries
*	23 (i)	Consent of KPMG LLP
*	23 (ii)	Consent of Miller and Lents, Ltd.

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	Exhibit Number	Description
*	24	Power of Attorney
*	31 (i)	Rule 13a-14(a)/15d-14(a) Certification-Chief Executive Officer
*	31 (ii)	Rule 13a-14(a)/15d-14(a) Certification-Chief Financial Officer
**	32	Section 1350 Certifications
*	99	Report of Miller and Lents, Ltd.
*	101 .INS	XBRL Instance Document
*	101 .SCH	XBRL Schema Document
*	101 .CAL	XBRL Calculation Linkbase Document
*	101 .DEF	XBRL Definition Linkbase Document
*	101 .LAB	XBRL Label Linkbase Document
*	101 .PRE	XBRL Presentation Linkbase Document

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company's Consolidated Financial Statements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION

February 20, 2015 By: /s/ ROBERT G. GWIN
Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2015.

Name and Signature	Title
(i) Principal executive officer and director:	
/s/ R. A. WALKER R. A. Walker	Chairman, President and Chief Executive Officer
(ii) Principal financial officer:	
/s/ ROBERT G. GWIN Robert G. Gwin	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ M. CATHY DOUGLAS M. Cathy Douglas	Senior Vice President, Chief Accounting Officer and Controller

(iv) Directors:*

ANTHONY R. CHASE
KEVIN P. CHILTON
H. PAULETT EBERHART
PETER J. FLUOR
RICHARD L. GEORGE
CHARLES W. GOODYEAR
JOSEPH W. GORDER
JOHN R. GORDON
MARK C. MCKINLEY
ERIC D. MULLINS

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN
Robert G. Gwin, Attorney-in-Fact

Exhibit 87

Intelligize®

Company:	COBALT INTERNATIONAL ENERGY, INC.
Document:	10-K (FY 2014) · 02/23/2015
	Entire Document
File Number:	001-34579
Pages:	156

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-34579

Cobalt International Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**27-0821169**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
(Address of principal executive offices, including zip code)

(713) 579-9100
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, $0.01 par value	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File

required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Act). Yes ☐ No ☒

As of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates was approximately $5.8 billion.

As of December 31, 2014, the registrant had 411,296,254 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement relating to the 2015 Annual Meeting of Shareholders, to be filed within 120 days of the end of the fiscal year covered by this report, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Cobalt International Energy, Inc.

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PART I

Cautionary Note Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains estimates and forward-looking statements, principally in "Business," "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations." Our estimates and forward-looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in this Annual Report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this Annual Report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect.

Our estimates and forward-looking statements may be influenced by the following factors, among others:

- our ability to successfully and efficiently execute our project appraisal, development and exploration activities;
- our liquidity and ability to finance our exploration, appraisal, development, and acquisition activities;
- oil and gas prices;
- lack or delay of partner, government and regulatory approvals related to our operations;
- projected and targeted capital expenditures and other costs and commitments;
- uncertainties inherent in making estimates of our oil and natural gas data;
- our dependence on our key management personnel and our ability to attract and retain qualified personnel;
- current and future government regulation of the oil and gas industry and our operations;
- changes in environmental, safety and health laws and regulations or the implementation or interpretation of those laws and regulations;
- our and our partners' ability to obtain permits and licenses and drill and develop our prospects and discoveries in the U.S. Gulf of Mexico and offshore West Africa;
- termination of or intervention in concessions, licenses, permits, rights or authorizations granted by the United States, Angolan and Gabonese governments to us;
- competition;
- our ability to find, acquire or gain access to new prospects and renew our exploration portfolio;
- the availability, cost and reliability of drilling rigs, containment resources, production equipment and facilities, supplies, personnel and oilfield services;
- the ability of the containment resources we have under contract to perform as designed or contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons;
- the availability and cost of developing appropriate infrastructure around and transportation to our prospects, discoveries and appraisal and development projects;
- military operations, civil unrest, disease, piracy, terrorist acts, wars or embargoes;

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- our vulnerability to severe weather events, especially tropical storms and hurricanes in the U.S. Gulf of Mexico;
- the cost and availability of adequate insurance coverage;
- the results or outcome of any legal proceedings or investigations we may be subject to;
- our ability to meet our obligations under the agreements governing our indebtedness; and
- other risk factors discussed in the "Risk Factors" section of this Annual Report on Form 10-K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words are intended to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this Annual Report on Form 10-K might not occur and our future results and our performance may differ materially from those expressed in these forward-looking statements due to, including, but not limited to, the factors mentioned above. Because of these uncertainties, you should not place undue reliance on these forward-looking statements.

Item 1. *Business*

OVERVIEW

We are an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. Since our founding in 2005, our oil-focused, below-salt exploration efforts have been successful in each of our three operating areas, resulting in ten discoveries out of the seventeen exploration prospects drilled. These ten discoveries consist of North Platte, Heidelberg, Shenandoah and Anchor in the U.S. Gulf of Mexico; Cameia, Lontra, Mavinga, Bicuar and Orca offshore Angola; and Diaman offshore Gabon. In addition, we have an interest in the Yucatan discovery in the U.S. Gulf of Mexico.

With these discoveries, our primary focus areas are:

1. **Project Appraisal and Development**—to progress our discoveries, which are currently in various stages of appraisal and development, toward project sanction and into proved reserves, production, and cash flow;
2. **Continued Exploration**—to simultaneously maintain an ongoing exploration program on our current acreage; and
3. **New Ventures**—to seek the renewal of our worldwide exploration portfolio in locations applicable to our deepwater and below-salt exploration strength.

Since inception, we have focused primarily on drilling exploration wells on our extensive below-salt exploration portfolio, which has resulted in the ten discoveries referenced above. With these discoveries in hand, our focus has now shifted towards selectively developing these discoveries and establishing production from them. Thus, our current strategy is to direct the majority of our capital expenditures toward project appraisal and development activities with the aim to increase our proved reserves and establish production and cash flow while continuing exploration on our existing acreage and seeking new venture opportunities for long-term growth.

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Each of our focus areas is discussed below by geographic region, followed by background information regarding the geology, plans for appraisal and development, licenses and leaseholds, drilling rigs and drilling results applicable to our geographic regions.

Project Appraisal and Development

U.S. Gulf of Mexico

We and our partners are moving forward on our Heidelberg, North Platte and Shenandoah appraisal and development projects and evaluating our Anchor discovery as described below:

Heidelberg Project. Our Heidelberg project was formally sanctioned in mid-2013, and Anadarko Petroleum Corporation ("Anadarko"), as operator, currently estimates first production from Heidelberg in the first half of 2016. On February 2, 2009, we announced that the Heidelberg #1 exploration well had encountered more than 200 feet of net pay thickness in Miocene horizons. Located in approximately 5,200 feet of water in Green Canyon Block 859 within the Miocene trend, this well was drilled to approximately 30,000 feet. An appraisal well was spud on the Heidelberg field in late 2011 in Green Canyon Block 903. On February 16, 2012, Anadarko announced the successful results of the appraisal well, which encountered approximately 250 feet of net pay thickness in high-quality Miocene sands. The appraisal well was drilled to a total depth of 31,030 feet in approximately 5,000 feet of water, about 1.5 miles south and 550 feet structurally up-dip from the Heidelberg #1 exploration well. Log and pressure data from the Heidelberg #1 exploration well and the Heidelberg appraisal well indicate excellent quality, continuous and pressure-connected reservoirs with high-quality oil. On April 19, 2012, Anadarko announced that a sidetrack well performed on the Heidelberg appraisal well successfully confirmed an extension of the Heidelberg field of up to 1,500 acres by encountering an oil/water contact that was approximately 700 feet down structure.

The Heidelberg production facility is designed to produce up to 80,000 barrels of oil per day ("BOPD") and 80 million cubic feet per day ("MMCFD") of gas. Anadarko, as operator, drilled the first field development well in 2014 and two additional development wells have recently reached total depth. Development drilling continues and is on schedule, with two drilling rigs currently operating in the field. The hull has arrived in the U.S. Gulf of Mexico, and the topsides are more than 70% complete. The subsea infrastructure remains on schedule to be fabricated and installed on time to support initial production in 2016. As of December 31, 2014, we had 8.4 million barrels ("MMBbls") of oil and 3.7 billion cubic feet ("Bcf") of gas of net proved undeveloped reserves attributed to the Heidelberg project. For more information regarding our proved undeveloped reserves, please see "—Summary of Oil and Gas Reserves." We own a 9.375% working interest in the Heidelberg project.

North Platte Project. On December 5, 2012, we announced a significant oil discovery at our North Platte prospect on Garden Banks Block 959 in the deepwater U.S. Gulf of Mexico. The North Platte #1 exploration well represents the first discovery in our deepwater U.S. Gulf of Mexico Alliance with TOTAL E&P USA INC. ("Total"). Based on extensive wireline evaluation, the discovery well encountered over 550 net feet of oil pay in multiple high-quality Inboard Lower Tertiary reservoirs. The North Platte oil discovery is particularly important because it provides evidence to support our geologic model of the Inboard Lower Tertiary trend where we hold a substantial acreage position with several potential follow-on exploration prospects, such as South Platte, Baffin Bay, Fraser, and Williams Fork. We conducted bypass coring on the North Platte #1 exploration well, which provided additional information we will use as we continue our evaluation of the North Platte oil discovery and plans for appraisal and development. The North Platte #1 exploration well is located in approximately 4,400 feet of water and was drilled to a total depth of approximately 34,500 feet.

In early 2015, we took delivery of the Rowan Reliance, a new-build, ultra-deepwater dynamically positioned drillship, which we plan to use for our operated U.S. Gulf of Mexico drilling campaign. We spud the North Platte #2 appraisal well with the Rowan Reliance in early February 2015. The results

from the North Platte #2 appraisal well will help us as we continue to evaluate the commerciality and potential development options for North Platte. In addition, we continue to analyze the data obtained from a 5,200 square mile full azimuth 3-D seismic survey over the greater North Platte area, of which we have licensed data covering approximately 1,350 square miles. This 3-D seismic survey is designed to further improve the sub-salt imaging of the North Platte field as well as several other Inboard Lower Tertiary exploration prospects in which we have working interests. We are using this 3-D seismic data to optimize potential appraisal and development well locations on North Platte. We are also conducting reservoir fluids analyses and subsea studies to support our appraisal and development efforts there. Reservoir characterization and certain geologic modeling studies are ongoing in order to better understand reservoir continuity, productivity and recovery characteristics of the field. The North Platte project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of North Platte and own a 60% working interest.

Shenandoah Project. On February 4, 2009, we announced that Anadarko, as operator, had drilled the Shenandoah #1 exploration well into Inboard Lower Tertiary horizons and encountered net oil pay approaching 300 feet. This well, located in approximately 5,750 feet of water in Walker Ridge Block 52, was drilled to approximately 30,000 feet. The Shenandoah #2 appraisal well was spud in the third quarter of 2012 in approximately 5,800 feet of water, about 1.3 miles southwest of the Shenandoah #1 exploration well and was drilled to a total depth of 31,405 feet. On March 19, 2013, we announced that the Shenandoah #2 appraisal well encountered more than 1,000 net feet of oil pay in multiple high quality Inboard Lower Tertiary reservoirs. The Shenandoah #3 appraisal well was spud in the second quarter of 2014 and evaluated the same well-developed reservoir sands 1,500 feet down-dip and 2.3 miles east of the first appraisal well. This well found an expanded geologic reservoir section, confirmed excellent reservoir qualities and delineated the potential oil-water contacts of the field. Planning is currently underway for another appraisal well, which we expect will be spud in the second quarter of 2015. The Shenandoah project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis prior to the preparation of a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Shenandoah project.

Yucatan Project. In the first quarter of 2014, we acquired a 5.34% non-operated working interest in the Yucatan discovery, which is an Inboard Lower Tertiary discovery located approximately three miles south of our Shenandoah discovery. Following this acquisition, we participated as a non-operator in the Yucatan #3 appraisal well, which reached total depth of 33,838 feet in the third quarter 2014 and encountered approximately 57 gross feet of pay in Lower Tertiary oil bearing sands down-dip of the initial discovery. The well results and data acquired are currently being evaluated and Shell, as operator, has transitioned the project over to its appraisal team. The Yucatan project is in the early stages of the project development life cycle and will require substantial additional evaluation and analysis, which may include additional appraisal drilling, prior to preparing a development plan and seeking potential formal project sanction. Given its proximity to the Shenandoah discovery, it is possible that any future development of Yucatan would tie-back to production facilities at Shenandoah.

Anchor Discovery. On January 6, 2015, we announced that the initial exploration well on our Anchor prospect had been drilled to a total depth of 33,749 feet and encountered significant high quality oil pay in multiple Inboard Lower Tertiary horizons. The Anchor discovery is located approximately 140 miles from the Louisiana coast in 5,183 feet of water. Chevron, as operator, expects to conduct additional appraisal drilling at Anchor in 2015. The Anchor discovery will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We own a 20% non-operated working interest in the Anchor discovery unit.

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West Africa

We and our partners are moving forward on our development projects and evaluating our additional discoveries offshore West Africa as described below:

Cameia Project (Block 21). On February 9, 2012, we announced that the Cameia #1 exploration well was drilled in 5,518 feet (1,682 meters) of water to a total depth of 16,030 feet (4,886 meters), at which point an extensive wire-line evaluation program was conducted. The results of this wire-line evaluation program confirmed the presence of a 1,180 foot (360 meter) gross continuous hydrocarbon column with over a 75% net to gross pay estimate. No gas/oil or oil/water contact was evident on the wire-line logs. An extended Drill Stem Test ("DST") was performed on the Cameia #1 exploration well to provide additional information. The DST flowed at an un-stimulated sustained rate of 5,010 barrels per day of 44-degree API gravity oil and 14.3 million cubic feet per day of associated gas (approximately 7,400 barrels of oil equivalent per day ("BOEPD")) with minimal bottom-hole pressure drawdown. Upon shut-in, the bottom-hole pressure reverted to its initial state in less than one minute. The well bore used in the DST had a perforated interval of less than one-third of the reservoir section. The flow rate, which was restricted by surface equipment, facility and safety precautions, confirmed the presence of a very thick, high quality reservoir. We believe the well, without such restrictions, would have the potential to produce in excess of 20,000 BOPD. On March 2, 2012, we submitted a declaration of commercial well to Sociedade National de Combustíveis de Angola—Empresa Pública ("Sonangol") with respect to the Cameia #1 exploration well. During 2012, we drilled the Cameia #2 appraisal well, which was located approximately 2.2 miles (3.5 kilometers) south of the Cameia #1 exploration well and was successful in demonstrating lateral continuity within the reservoir originally encountered by the Cameia #1 exploration well. The results from the Cameia #2 appraisal well were also important as the well discovered a lower hydrocarbon-bearing zone at least 440 feet (134 meters) deeper than that which was observed in the Cameia #1 exploration well.

On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia discovery. In mid-April 2014, we spud the Cameia #3 appraisal well, which we expect to utilize as a production well in the Cameia field development. The results of the Cameia #3 appraisal well were successful and consistent with pre-drill expectations. A successful DST was also conducted on the Cameia #3 appraisal well. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Given the current commodity price environment, we believe an opportunity exists to review the project design concept and projected capital expenditures in order to optimize the cost and scale of the Cameia development and production facilities prior to formal project sanction. During 2015, we intend to pursue project cost reductions in light of the current weakness in the market for goods and services utilized in major offshore development projects. We remain committed to progressing the Cameia development towards project sanction and production, and, to that end, we plan to spud the Cameia #4 well in the first quarter of 2015, which we intend to utilize as a production well. Following drilling operations on Cameia #4, during 2015 we anticipate drilling a water injection well, returning to Cameia #3 to re-complete it as a production well, and also drilling another production well and a gas injection well, all for the Cameia development. We expect to achieve formal project sanction of Cameia by year-end 2015, and first production from Cameia will likely occur in 2018. The occurrence and timing of project sanction and first production from Cameia are subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum. We are the operator of and hold a 40% working interest in the Cameia project. Our partner in the Cameia project is Sonangol Pesquisa e Produção, S.A. ("Sonangol P&P"), with a 60% working interest.

Greater Orca Lontra Development (GOLD) Project (Block 20). In the first quarter of 2014, we drilled the successful Orca #1 exploration well on Block 20 offshore Angola to a measured depth of 12,703 feet (3,872 meters) and encountered approximately 250 feet (75 meters) of net oil pay in the sag

and syn-rift reservoirs. A DST was conducted on the Orca #1 exploration well, and the well was successfully tested at a facility-constrained rate of 3,700 barrels of oil per day and 16.3 million cubic feet of gas per day with minimal drawdown (approximately 1%) in the upper sag section of the discovery. The results of this DST confirm that the Orca #1 exploration well is capable of substantial sustained oil production rates. On April 28, 2014, we submitted a declaration of commercial well to Sonangol regarding the Orca #1 exploration well. In late 2014, we spud the Orca #2 appraisal well, and operations on this well are ongoing.

On December 1, 2013, we announced that our Lontra #1 exploration well had been drilled to a total depth of 13,763 feet (4,195 meters) and encountered approximately 250 feet (75 meters) of net pay in a very high quality reservoir section. The Lontra #1 exploration well encountered both a high liquids content gas interval and an oil interval. A DST was performed on the high liquids content gas interval and successfully produced a sustained flow rate of 2,500 barrels per day of condensate and 39 million cubic feet per day of gas. The DST did not test the oil interval. On December 20, 2013, we submitted a declaration of commercial well to Sonangol regarding the Lontra #1 exploration well.

Given the geographical proximity of the Lontra discovery and the Orca discovery, both on Block 20 offshore Angola, our initial development concept is to tie-back the Lontra field to the Orca field as part of a hub development and to proceed with the development of the oil and condensate from the Orca and Lontra fields. The Greater Orca Lontra Development (GOLD) project is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including additional appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of the GOLD project with a 40% working interest. Our partners in the GOLD project include BP Exploration Angola (Kwanza Benguela) Limited ("BP") and Sonangol P&P, with each partner holding a 30% working interest.

Bicuar Discovery (Block 21). On January 22, 2014, we announced that the Bicuar #1A exploration well was successfully drilled to a total depth of 18,829 feet (5,739 meters) and encountered approximately 180 feet (56 meters) of net pay from multiple pre-salt intervals. Results of an extensive logging, coring and fluid acquisition program confirmed the existence of both oil and condensate in multiple intervals. No free gas zones or water contacts were observed. The results from the Bicuar #1A exploration well are significant because they confirm the first discovery of mobile hydrocarbons tested in the pre-salt syn-rift geologic interval offshore Angola. On February 13, 2014, we submitted a declaration of commercial well to Sonangol regarding the Bicuar #1A exploration well. The Bicuar discovery is in the early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. We are the operator of and have a 40% working interest in the Bicuar discovery. Our partner in Bicuar is Sonangol P&P, with a 60% working interest.

Mavinga Discovery (Block 21). On October 29, 2013, we announced that the Mavinga #1 exploration well had reached total depth and encountered approximately 100 feet (30 meters) of net oil pay. This discovery was confirmed by the successful production of oil from mini DSTs, direct pressure and permeability measurements and log and core analysis. Efforts to establish a sustained flow rate from a full DST were not successful. We believe that operational issues associated with the DST prevented the production from the oil reservoir during the production test. We estimate a gross oil column of up to 650 feet (200 meters) at the crest of the Mavinga structure updip of the Mavinga #1 exploration well. Additional drilling will be required to confirm the ultimate gross thickness of the crest of the Mavinga structure and Mavinga's reservoir quality. On November 12, 2013, we submitted a declaration of commercial well to Sonangol regarding the Mavinga #1 exploration well. The Mavinga discovery is in the very early stages of the development life-cycle and will require substantial additional evaluation and analysis, potentially including appraisal drilling, prior to preparing a development plan and seeking formal project sanction. Given the results of the Mavinga #1 exploration well and its proximity to the location of our Cameia project, our initial development concept for the Mavinga

discovery is to eventually tie back the Mavinga field to our Cameia project. Although we estimate formal sanction of the Cameia project by year-end 2015 and first production from the Cameia project in 2018 (subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum) those estimates and timelines do not include any potential tie-back development to or production from our Mavinga discovery. We are currently unable to estimate when the Mavinga discovery might be sanctioned or when we might achieve first production. We are the operator of and have a 40% working interest in the Mavinga discovery. Our partner in Mavinga is Sonangol P&P, with a 60% working interest.

Diaman Discovery (Diaba Block). On August 19, 2013, we announced that the Diaman #1B exploration well was drilled to a total depth of 18,323 feet (5,585 meters), and encountered approximately 160 to 180 feet (50 to 55 meters) of net hydrocarbons in the objective pre-salt formations on the Diaba Block offshore Gabon. The Diaman #1B exploration well successfully confirmed the existence of a working petroleum system, a salt seal, and high-quality sandstone reservoirs. We and our partners are continuing to analyze additional 3-D seismic data we acquired over the Diaba block in 2014. The operator currently expects to resume exploration drilling on the Diaba block offshore Gabon in 2016. Diaman is in the very early stages of the project development life-cycle and will require substantial additional evaluation and analysis, including appraisal drilling, prior to proceeding with any development plan. We have a 21.25% non-operated working interest in the Diaman discovery. Our partners in the Diaman discovery include Total Gabon, as operator (42.5% working interest), Marathon Petroleum Corporation (21.25% working interest), and the Republic of Gabon (15% working interest).

Continued Exploration

U.S. Gulf of Mexico

We currently have several below-salt exploration prospects in the deepwater U.S. Gulf of Mexico. Although we plan to utilize the Rowan Reliance, our only operated rig in the U.S. Gulf of Mexico, primarily for appraisal and development work, we will continue to mature our operated below-salt prospect inventory through seismic acquisition and evaluation and well permitting activities for future exploration drilling. We plan to drill one to two exploration wells per year in the U.S. Gulf of Mexico, although the order and timing of our exploration drilling is dependent on several factors and may vary over time. Specifically, we plan to focus on maturing our Rocky Mountain Miocene prospect as well as our South Platte, Baffin Bay, Fraser, and Williams Fork prospects, which are Inboard Lower Tertiary prospects in close proximity to our North Platte #1 discovery. Furthermore, we may elect to participate as a non-operator in the Goodfellow #1 exploration well, which will target Inboard Lower Tertiary horizons. Currently we have a 21.2% working interest in the Goodfellow prospect and our partners include ENI U.S. Operating Co. Inc. (25.7%), Samson Offshore, LLC (25.7%), and Total (27.4%). Prior to spudding the Goodfellow #1 exploration well, the composition and working interests of the Goodfellow partnership may change. See "Risk Factors—Risks Relating to Our Business—Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing."

West Africa

We also currently have several pre-salt exploration prospects offshore West Africa. Although we plan to utilize the SSV Petroserv Catarina, our only operated rig offshore West Africa, primarily on the appraisal and development of our existing discoveries, we plan to continue maturing up to 20 follow-on oil-focused exploration prospects on Blocks 20 and 21 offshore Angola. We plan to continue our exploration efforts offshore West Africa, although the order and timing of any exploration drilling is dependent on several factors and may vary over time. See "Risk Factors—Risks Relating to Our

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Business—Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing."

New Ventures

In addition to our existing assets in the U.S. Gulf of Mexico and offshore West Africa and in furtherance of our strategy of renewing our world-wide exploration portfolio, our New Ventures group is actively evaluating additional exploration opportunities. Consistent with our core strengths, our New Ventures strategy is centered on pursuing high-value, deepwater oil-focused exploration opportunities in frontier and under-explored basins. Our New Ventures strategy continues to focus on the Atlantic Basin, specifically opportunities in Mexico and the Canadian East Coast.

Exploration Prospect Maturation Process

The process of maturing an exploration prospect from initial identification to drill-ready status begins with analyzing regional data, including industry well results, to understand a given trend's specific geology and defining those areas, or "prospects," that offer the highest potential for substantial hydrocarbon deposits while minimizing geologic risks. After these prospects are identified, we further mature our prospects by acquiring and reprocessing high resolution seismic data available in the potential prospect's direct vicinity. This includes advanced imaging information, such as wide-azimuth studies, to further our understanding of a particular prospect's characteristics, including both trapping mechanics and fluid migration patterns. Reprocessing is accomplished through a series of model building steps that incorporate the geometry of the salt and below salt geology to optimize the final image. In addition, we gather publicly available information, such as well logs, which we use to evaluate industry results and activities in order to understand the relationships between industry-drilled prospects and our portfolio of undrilled prospects. As part of the maturation of a prospect to drill-ready status, we also perform substantial drilling-related engineering work, such as generating a proposed well design, including the well evaluation and completion design, and the preparation of pore pressure prediction analysis and reports, site survey reports, and shallow hazard reports. The purpose of this work is to minimize the drilling and operational risk associated with drilling a well on a particular prospect. There are also numerous regulatory filings we must prepare and submit in order to obtain the required permits, authorizations and approvals needed to drill an exploration well on a prospect.

We may decide during any of the foregoing steps of prospect maturation that drilling an exploration well on a particular prospect may not be warranted given the geologic, drilling and economic risk profile that was developed during the prospect maturation process. Once the foregoing items, as applicable, are complete and we have determined that a prospect is ready and desirable for exploration drilling, and the geologic, economic and drilling risks associated with such prospect have been optimally mitigated, such prospect would be considered "mature."

General Information—U.S. Gulf of Mexico

Our U.S. Gulf of Mexico operations target oil-focused prospects in the subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico.

Geologic Overview

The subsalt Miocene and Inboard Lower Tertiary horizons in the deepwater U.S. Gulf of Mexico are characterized by well-defined hydrocarbon systems, comprised primarily of high-quality source rock and crude oil, and contain several of the most significant hydrocarbon discoveries in the deepwater U.S. Gulf of Mexico in recent years.

Miocene. The subsalt Miocene trend is an established play in the deepwater U.S. Gulf of Mexico. Discoveries in this trend include Heidelberg, Thunder Horse, Atlantis, Tahiti, Mad Dog, and Stampede.

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This trend is characterized by high quality reservoirs and fluid properties, resulting in high production well rates.

Inboard Lower Tertiary. The Lower Tertiary horizon is an older formation than the Miocene, and, as such, is generally deeper, with greater geologic complexity. The industry has been successful in terms of locating and drilling large hydrocarbon-bearing structures in this interval. The reservoir quality of the Lower Tertiary has proven to be highly variable. Some regions, including those areas in which many of the historical Lower Tertiary discoveries have been made, exhibit lower permeability and generally lower natural gas content compared to the Miocene horizon.

However, a sub-region in the Lower Tertiary that has exhibited reservoir characteristics more similar to that of existing Miocene discoveries is the Inboard Lower Tertiary trend, which includes our oil discoveries at North Platte, Shenandoah and Anchor. The Inboard Lower Tertiary is a trend located to the north of existing Outboard Lower Tertiary fields such as St. Malo, Jack and Cascade, which are all on production from the Lower Tertiary. We were an early mover in the Inboard Lower Tertiary trend, targeting specific lease blocks as early as 2006. We believe our Inboard Lower Tertiary prospects are characterized by large, well-defined structures of a similar size to historic Outboard Lower Tertiary discoveries, but are differentiated by what we believe to be better reservoir quality and energy based upon data from wells drilled at our North Platte, Shenandoah and Anchor discoveries. We believe we hold a significant leasehold position in the Inboard Lower Tertiary and, to date, have had an exploration success rate of 60% in the Inboard Lower Tertiary.

Plans for Appraisal and Development

In general, the life-cycle of our major project developments begins with a thorough evaluation and analysis of well logs (including offset analog wells), reservoir core samples, fluid samples and, in some cases, the results of production tests from the initial exploration well that encountered what we believe may be commercial hydrocarbons. This information, along with relevant seismic data, is used to generate locations and plans for appraisal and development wells. Depending upon the project, we may choose to drill one or more appraisal wells prior to project sanction and development, each of which will undergo thorough analysis and evaluation. The information we obtain from exploration and appraisal wells is then used to create a development plan, which will include economic assumptions on the costs of drilling and completing development wells, the front-end engineering and design of offshore production and processing facilities, including subsea, umbilical, riser and flowline systems and other related transportation infrastructure. The project will become formally sanctioned when the relevant working interest partners have approved the development plan. Typically, following formal project sanction, we will commence the construction of offshore production facilities, and proceed with development drilling and the installation of subsea architecture in order to advance the project towards initial production.

A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a project development will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation and analysis, such as the steps described above, will need to be performed prior to official project sanction and development. In addition, substantial amounts of capital are required to progress a project through the project development life-cycle. At any time during the project development life-cycle, we may determine that the project would be uneconomic and abandon the project, despite the fact that the initial exploration well, or subsequent appraisal wells, discovered hydrocarbons. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

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Leasehold Acreage

As of December 31, 2014, we owned interests in 266 blocks within the deepwater U.S. Gulf of Mexico, representing approximately 1.5 million gross (0.8 million net) acres. We are the designated operator of 238 of these blocks, or approximately 89% of our U.S. Gulf of Mexico leasehold acreage. The following schedule shows the developed and undeveloped acres in which we held interests as of December 31, 2014 in the U.S. Gulf of Mexico.

	Developed Lease Acres(1)		Undeveloped Lease Acres(2)	
	Gross	Net	Gross	Net
U.S. Gulf of Mexico	17,280	1,620	1,494,470	764,308

(1) Our developed lease positions of 17,280 gross (1,620 net) acres are entirely related to our Heidelberg project. The Heidelberg project was sanctioned for development in mid-2013 and all of the leasehold acreage associated with the Heidelberg project is held by a Suspension of Production, which was granted by the U.S. Department of the Interior for the federally-approved Heidelberg Unit. Anadarko, as operator, estimates first oil production from Heidelberg in the first half of 2016.

(2) Our Shenandoah, Anchor and North Platte projects are not yet sanctioned for development and therefore the acreage associated with these projects remains classified as undeveloped. We estimate that the North Platte project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 34,560 gross (20,736 net) acres; the Shenandoah project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 14,400 gross (2,880 net) acres; and the Anchor project covers U.S. Gulf of Mexico blocks, either wholly or partially, representing 20,160 gross (4,032 net) acres. If development projects related to North Platte, Anchor and Shenandoah are sanctioned, we will evaluate which acreage associated with these projects could then be classified as developed acreage.

The royalties on our lease blocks range from 12.5% to 18.75% with an average of 16.34%.

Most of our U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2024. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary lease term, our leases would extend beyond the primary term, generally for the life of production. Our leasehold interest in the U.S. Gulf of Mexico increased by 113,760 gross (65,804 net) acres in 2014. This increase was due to the acquisition of 53 blocks through the Central Gulf of Mexico lease sale 231 and certain trades with other industry participants, which were offset by the relinquishment of 30 blocks as a result of lease expiration, trade and sale.

The table below summarizes our undeveloped acreage scheduled to expire in the next five years in the U.S. Gulf of Mexico.

	Undeveloped Lease Acres Expiry									
	2015(1)(3)		2016(1)(2)(3)		2017(3)		2018(1)(3)		2019 and thereafter(1)(2)(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S. Gulf of Mexico	57,600	16,783	362,880	203,109	92,160	46,388	595,910	287,131	368,640	207,441

(1) The gross and net acreage numbers reflected in these columns include portions of the estimated 14,400 gross (2,880 net) acres covering U.S. Gulf of Mexico blocks associated with our Shenandoah project, upon which exploration and appraisal wells have both discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Shenandoah

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project is now part of the Shenandoah Unit, federally approved in 2014. We expect that the operator of the Shenandoah Unit will conduct additional appraisal drilling operations in 2015 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Shenandoah Unit.

(2) The gross and net acreage numbers reflected in these columns include portions of the estimated 34,560 gross (20,736 net) acres covering U.S. Gulf of Mexico blocks associated with our North Platte project, upon which an exploration well has discovered hydrocarbons, but a development project has not yet been sanctioned. We plan to perpetuate this acreage by an eventual unitization and sanctioned development plan and by applying for approval of a Suspension of Production.

(3) The gross and net acreage number reflected in these columns include portions of the estimated 20,160 gross (4,032 net) acres covering U.S. Gulf of Mexico blocks associated with our Anchor project, upon which an exploration well has discovered hydrocarbons, but a development project has not yet been sanctioned. The leasehold acreage in the Anchor project is now part of the Anchor Unit, federally approved in 2014. We expect that the operator of the Anchor Unit will conduct additional appraisal drilling operations in 2015 and eventually file for approval of a Suspension of Production in order to perpetuate all of the acreage associated with the Anchor Unit.

The acreage numbers in the table above do not reflect (i) 5,760 gross (1,152 net) acres covering leases associated with our Shenandoah project whose primary term expired in 2014 but are being held by continuous operations on the Shenandoah project, or (ii) 11,520 gross (2,304 net) acres covering leases associated with our Anchor project whose primary term expired in 2014 but are being held by continuous operations on the Anchor project. We expect that the operators of both Shenandoah and Anchor will continue to conduct operations on these projects during 2015 and eventually file for approval of a Suspension of Production in order to perpetuate this acreage. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

Drilling Rigs

On August 5, 2013, we executed a drilling contract with Rowan Reliance Limited, an affiliate of Rowan Companies plc, for the Rowan Reliance, a new-build, ultra-deepwater dynamically positioned drillship that is currently drilling our North Platte #2 appraisal well. The Rowan Reliance drillship is capable of operating in water depths of up to 12,000 feet and drilling to measured depths of up to 40,000 feet. The drilling contract provides for a firm three-year commitment, which began in February 2015, at a day rate of approximately $602,000 (inclusive of mobilization fees) and two one-year extension options at day rates to be mutually agreed.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled in the deepwater U.S. Gulf of Mexico during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that

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proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	U.S. Gulf of Mexico(1)					
	2014(2)		2013(3)		2012(4)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration						
Productive	1	0.2	1	0.2	2	0.69375
Dry	2	0.2534	2	1.02	1	0.45
Development						
Productive	1	0.09375	—	—	—	—
Dry	—	—	—	—	—	—
Total	4	0.54715	3	1.22	3	1.14375

(1) We did not drill any development wells in the U.S. Gulf of Mexico during the fiscal years ended December 31, 2013 and 2012, respectively.

(2) The wells noted include our Anchor #1 exploration well (productive), Shenandoah #3 appraisal well (dry), Yucatan #3 appraisal well (dry) and a Heidelberg development well (productive). The number of development wells does not include two Heidelberg development wells that were drilling as of December 31, 2014, one of which reached total depth in January 2015 and the other reached total depth in February 2015.

(3) The wells noted include our Shenandoah #2R appraisal well (productive), and our Ardennes #1 (dry) and Aegean #1 (dry) exploration wells.

(4) The wells noted include our North Platte #1 (productive) and Ligurian #2 (dry) exploration wells and our Heidelberg #3 appraisal well (productive).

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling in the U.S. Gulf of Mexico (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

U.S. Gulf of Mexico	
Gross(1)	**Net(1)**
1	0.6

(1) The well noted is the North Platte #2 appraisal well (60% working interest).

Strategic Relationship with Total

On April 6, 2009, we announced a long-term alliance with Total in which, through a series of transactions, we combined our respective U.S. Gulf of Mexico exploration lease inventory (which excludes our Heidelberg project, our Shenandoah project, and all developed or producing properties held by Total in the U.S. Gulf of Mexico) through the exchange of a 40% interest in our leases for a 60% interest in Total's leases, resulting in a current combined alliance portfolio covering 239 blocks. The initial mandatory five-well program and Total's obligation to carry a substantial share of our costs associated with those wells concluded at the end of drilling operations on our Aegean #1 exploration well. Pursuant to the alliance, Total remains obligated to pay 40% of the general and administrative costs relating to our operations in the deepwater U.S. Gulf of Mexico during the 10-year alliance term. Total also remains obligated to pay up to $75 million to carry up to two-thirds of (i) our costs for

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drilling or other operations (including seismic) conducted prior to the development phase on our North Platte project, and (ii) our costs for any additional exploration or appraisal wells apart from our North Platte project. We act as operator on behalf of the alliance through the exploration and appraisal phases of development. Upon completion of appraisal operations, operatorship will be determined by Total and ourselves, with the greatest importance being placed on majority (or largest) working interest ownership and the respective experience of each party in developments which have required the design, construction and ownership of a permanently anchored host facility to collect and transport oil or natural gas from such development.

General Information—West Africa

Our West Africa operations include appraisal and development activities on our discoveries as well as the exploration of oil-focused prospects targeting pre-salt geologic horizons in the Kwanza basin offshore Angola and the South Gabon Coastal basin offshore Gabon.

Geologic Overview

Offshore Angola and Gabon are characterized by the presence of salt formations and oil-bearing sediments located in pre-salt and above salt (Albian) horizons. Given the rifting that occurred when plate tectonics separated the South American and African continents, we believe the geology offshore Angola (Kwanza Basin) and Gabon (South Gabon Coastal Basin) is an analog to the geology offshore Brazil where several pre-salt discoveries are located. The basis for this hypothesis is that 150 million years ago, current day South America and Africa were part of a larger continent that broke apart. As these land masses slowly drifted away from each other, rift basins formed. These basins were filled with organic rich material and sediments, which in time became hydrocarbon source rocks and reservoirs. A thick salt layer was subsequently deposited, forming a seal over the reservoirs. Finally the continents continued to drift apart, forming two symmetric geologic areas separated by the Atlantic Ocean. This symmetry in geology is particularly notable in the deepwater areas offshore Gabon, Angola and the Campos Basin offshore Brazil. From an exploration perspective, we believe this similarity is very meaningful, particularly in the context of pre-salt Brazilian discoveries and our recent pre-salt discoveries at Cameia, Lontra, Mavinga, Bicuar, Orca and Diaman.

Plans for Appraisal and Development

In general, the life-cycle of our major project developments begins with a thorough evaluation and analysis of well logs, reservoir core samples, fluid samples and, in some cases, the results of production tests from the initial exploration well that encountered what we believe may be commercial hydrocarbons. This information, along with relevant seismic data, is used to generate locations and plans for appraisal and development wells. In Angola, there are also important regulatory approvals we must obtain from Sonangol throughout the project development life-cycle. For example, under the terms of our applicable licenses in Angola, following a successful exploration well we are required to file a declaration of commercial well with Sonangol, which we have done with respect to our Cameia #1, Mavinga #1, Lontra #1, Bicuar #1A, and Orca #1 exploration wells. Under the terms of our applicable licenses in Angola, we have two years from our declaration of commercial well to declare a commercial discovery, unless otherwise agreed by Sonangol. On February 28, 2014, we submitted a formal declaration of commercial discovery to Sonangol with respect to our Cameia project. Depending upon the project, we may choose to drill one or more appraisal wells, each of which will undergo thorough analysis and evaluation. Once we file a declaration of commercial discovery with Sonangol, we have three months to file a development plan with Sonangol for approval. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. The development plan will include economic assumptions on the costs and timeline for drilling and completing

development wells, the front-end engineering design, procurement, installation and commissioning of offshore production and processing facilities such as FPSO vessels, and also includes engineering design, procurement, installation and commissioning of subsea, umbilical, riser and flowline systems and other related transportation infrastructure. The project will become formally sanctioned when the relevant working interest partners have approved the development plan, including Sonangol and the Angola Ministry of Petroleum. Typically, following formal project sanction, we will commence the construction of offshore production facilities, proceed with development drilling and installation of subsea architecture in order to advance the project towards initial production. With respect to our Cameia development, we plan to conduct certain development drilling prior to formal project sanction.

A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a project development will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation and analysis, such as the steps described above, will need to be performed prior to official project sanction and development, including important regulatory approvals. At any time during the project development life-cycle, we may determine that the project would be uneconomic and abandon the project, despite the fact that the initial exploration well, or subsequent appraisal or development wells, discovered hydrocarbons. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

Licenses

Block 9 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 9 offshore Angola by executing a Risk Services Agreement ("Block 9 RSA") with Sonangol. The Block 9 RSA governs our 40% working interest in and operatorship of Block 9 offshore Angola and forms the basis of our exploration, development and production operations on this block. The Block 9 RSA provides for an initial exploration period of four years. On April 3, 2014, the Angola Ministry of Petroleum published Executive Decree 95/14, which granted us a two-year extension of the initial exploration phase on Block 9 offshore Angola, which is now scheduled to expire on March 1, 2016, and an optional exploration period of an additional three years. We do not have contractual rights to sell natural gas on Block 9, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 9. Block 9 is approximately 1 million acres (4,000 square kilometers) in size or approximately 167 U.S. Gulf of Mexico blocks and is located immediately offshore in the southeastern-most portion of the Kwanza Basin. Water depth ranges from zero to more than 3,200 feet (1,000 meters). Sonangol P&P is our partner on Block 9 and holds a 60% working interest. For more information regarding our Block 9 license, please see "—Material Agreements—Risk Services Agreements for Blocks 9 and 21 Offshore Angola."

Block 21 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 21 offshore Angola by executing a Risk Services Agreement ("Block 21 RSA") with Sonangol. The Block 21 RSA governs our 40% working interest in and operatorship of Block 21 offshore Angola and forms the basis of our exploration, development and production operations on this block. The Block 21 RSA provides for an initial exploration period of five years, which is scheduled to expire on March 1, 2015. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We do not have contractual rights to sell natural gas on Block 21, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21. Block 21 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately

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200 U.S. Gulf of Mexico blocks. The block is 30 to 90 miles (50 to 140 kilometers) offshore in water depths of 1,300 to 5,900 feet (400 to 1,800 meters) in the central portion of the Kwanza Basin. Sonangol P&P is our partner on Block 21 and holds a 60% working interest. For more information regarding our Block 21 license, please see "—Material Agreements—Risk Services Agreements for Blocks 9 and 21 Offshore Angola."

On August 26, 2014, we received documentation confirming that Nazaki Oil and Gaz ("Nazaki") and Alper Oil Limitada ("Alper") are no longer members of the contractor group of Blocks 9 and 21 offshore Angola. Pursuant to a series of Executive Decrees passed by the Republic of Angola, the working interests previously held by Nazaki and Alper in Blocks 9 and 21 have been transferred to and are now held by Sonangol P&P. As a result, we no longer have any relationship with Nazaki or Alper. The contractor groups for Blocks 9 and 21 offshore Angola now consist only of Sonangol P&P (60% working interest) and the Company (40% working interest). Our obligation to carry and pay for Alper's 10% working interest terminated immediately with the transfer of Alper's interest to Sonangol P&P pursuant to the terms of our 2010 agreements with Alper. As a result, our paying interest in these blocks has been reduced from 62.5% to 52.5% during the initial exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. In addition, all historical costs of our carry of Alper will be recouped by us from Sonangol P&P's share of production revenues from these blocks. We are the operator of Blocks 9 and 21.

Block 20 offshore Angola. We acquired our license to explore for, develop and produce oil from Block 20 offshore Angola by executing a Production Sharing Contract (the "Block 20 PSC") with Sonangol. The Block 20 PSC governs our 40% working interest in and operatorship of Block 20 offshore Angola and forms the basis of our exploration, development and production operations on Block 20 offshore Angola. Sonangol P&P and BP are the other holders of working interests under the Block 20 PSC. The Block 20 PSC provides for an initial exploration period of five years, which is scheduled to expire on January 1, 2017, and an optional exploration period of an additional three years. We do not have contractual rights to sell natural gas on Block 20 offshore Angola, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20. Block 20 is approximately 1.2 million acres (4,900 square kilometers) in size or approximately 200 U.S. Gulf of Mexico blocks and is centered approximately 75 miles west of Luanda in the deepwater Kwanza Basin. It is immediately to the north of Block 21. For more information regarding our Block 20 license, please see "—Material Agreements—Production Sharing Contract for Block 20 Offshore Angola."

Diaba Block offshore Gabon. We acquired our non-operated 21.25% working interest in the Diaba Block offshore Gabon by entering into an assignment agreement with Total Gabon. Through the assignment we became a party to the Production Sharing Agreement ("PSA") between the operator Total Gabon and the Republic of Gabon. The PSA gives us the right to recover costs incurred and receive a share of the remaining profit from any commercial discoveries made on the block. We have contractual rights to any form of hydrocarbons, including natural gas, discovered on our Gabon license area. The Diaba Block is approximately 2.2 million acres (9,100 square kilometers) in size or approximately 370 U.S. Gulf of Mexico blocks. The block is 40 to 120 miles (60 to 200 kilometers) offshore in water depths of 300 to 10,500 feet (100 to 3,200 meters) in the central portion of the offshore South Gabon Coastal basin.

As of December 31, 2014, our working interests in Blocks 9, 20 and 21 offshore Angola and the Diaba Block offshore Gabon comprised an aggregate 5,652,687 gross (1,840,581 net) undeveloped acres. We do not currently own any working interests in developed acreage offshore Angola, although exploration wells have discovered hydrocarbons at Cameia, Mavinga and Bicuar on Block 21 offshore Angola and at Lontra and Orca on Block 20 offshore Angola. We have filed a declaration of commercial well with respect to each of those exploration wells pursuant to the terms of the Block 21 RSA and the Block 20 PSC. On February 28, 2014, we submitted a formal declaration of commercial

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discovery to Sonangol with respect to our Cameia project. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Upon the approval of a development area by the applicable Angolan government authorities, we will be in a position to specify the acreage assigned to the Cameia project. Likewise, upon approval of development areas by the applicable Angolan government authorities with respect to each of our Mavinga, Bicuar, Lontra and Orca discoveries, we will be in a position to specify the acreage assigned to each respective discovery. In addition, the Diaman #1B exploration well on the Diaba Block offshore Gabon was also successful in discovering hydrocarbons, however, the Diaman discovery remains in the early phases of the development project life-cycle. After the approval of a development plan, the delineation of a development area and the completion of certain other steps, we will evaluate which acreage associated with these discoveries could then be classified as developed acreage. See "Risk Factors—Risks Relating to Our Business—Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production."

The table below summarizes our undeveloped acreage scheduled to expire in the next five years offshore West Africa.

	Undeveloped Acres Expiring									
	2015		2016		2017		2018		2019 and thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Offshore West Africa										
Angola:										
Block 9(1)	—	—	988,668	395,467	—	—	—	—	—	—
Block 20(2)	—	—	—	—	1,210,569	484,228	—	—	—	—
Block 21(3)	1,210,816	484,326	—	—	—	—	—	—	—	—
Gabon:										
Diaba(4)	—	—	2,242,634	476,560	—	—	—	—	—	—

(1) Pursuant to the Block 9 RSA and Executive Decree 95/14, which granted us a two-year extension of the initial exploration phase on Block 9 offshore Angola, our Block 9 acreage is now scheduled to expire as of March 1, 2016.

(2) Pursuant to the Block 20 PSC, our license to exploration acreage on Block 20 will expire as of January 1, 2017, subject to certain extensions. This expiration date may be extended by three years if we notify Sonangol in writing of such extension at least thirty days before January 1, 2017, provided we have otherwise fulfilled our obligations under the agreement and agree to drill additional wells pursuant to the Block 20 PSC. The undeveloped acreage numbers listed in this row include acreage associated with our Lontra and Orca discoveries upon which exploration wells have discovered hydrocarbons, but a formal declaration of commercial discovery has not yet been filed with the applicable Angolan government authorities and therefore an associated development area has not yet been approved.

(3) Pursuant to the Block 21 RSA, our license to exploration acreage on Block 21 will expire as of March 1, 2015, subject to certain extensions. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue to pursue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. The undeveloped acreage numbers listed in this row include acreage associated with our Cameia, Mavinga and Bicuar projects upon which exploration wells have discovered hydrocarbons and we have filed declarations of commercial wells, but associated development areas have not yet been approved. See "Risk Factors—Risks Relating to Our Business—Under the

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terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

(4) Pursuant to the PSA governing the Diaba Block, our license to acreage not defined by an approved development area will expire as of December 31, 2016, subject to certain extensions.

Drilling Rigs

We currently have the Petroserv SSV Catarina under contract for use in our offshore Angolan pre-salt drilling campaign. The drilling contract for the SSV Catarina, a new-build, sixth-generation semi-submersible drilling rig commenced in April 2013 and provides for a firm three-year commitment at a day rate of approximately $600,000 and two one-year extension options at day rates to be mutually agreed. Such rates are subject to standard reimbursement and escalation contractual provisions. We plan to utilize the Petroserv SSV Catarina for exploration, appraisal and development activities offshore Angola.

Prior Drilling Results and Drilling Statistics

The following table sets forth information with respect to the gross and net oil and gas wells we drilled offshore West Africa during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of any reserves found. Productive wells include wells that have been drilled to the targeted depth and prove, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well. A dry well is an exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Offshore West Africa					
	2014(2)		2013(3)		2012(4)	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploration(1)						
Productive	3	1.2	3	1.0125	2	0.8
Dry	2	0.8	—	—	—	—
Total	5	2.0	3	1.0125	2	0.8

(1) We did not drill any development wells offshore West Africa during the fiscal years ended December 31, 2014, 2013, and 2012, respectively, although we expect that the Cameia #3 appraisal well which was drilled in 2014 will be used as a field development well.

(2) The wells noted include our Orca #1 exploration well (productive), Bicuar #1A exploration well (productive), Cameia #3 appraisal well (productive), Loengo #1 exploration well (dry), and Mupa #1 exploration well (dry).

(3) The wells noted include our Mavinga #1, Lontra #1, and Diaman #1B exploration wells (all productive).

(4) The wells noted include our Cameia #1 exploration well and Cameia #2 appraisal well (all productive).

The following table sets forth information with respect to the gross and net oil and gas wells that are currently drilling offshore West Africa (including wells that are temporarily suspended) as of the date of this Annual Report on Form 10-K, but does not include oil and gas wells that have been drilled

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to their targeted depth and have subsequently been either temporarily or permanently plugged and abandoned.

West Africa	
Gross(1)	Net(1)
1	0.40

(1) The well noted is the Orca #2 appraisal well.

Summary of Oil and Gas Reserves

The summary data with respect to our estimated proved reserves and future cash flows has been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm, in accordance with the definitions and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities and adjusted for imbalances. The December 31, 2014 reserve report was completed on January 22, 2015, and a copy is included as an exhibit to this report.

Proved Reserves

As of December 31, 2014, our estimated net proved undeveloped reserves totaled 8.4 MMBbls of oil and 3.7 Bcf of natural gas. All of our proved reserves are attributable to our interest in the Heidelberg field in the U.S. Gulf of Mexico.

	Estimated Net Proved Reserves as of December 31, 2014		
	Oil (MMBbls)	Natural Gas (Bcf)	Total (MMBOE)
Proved Developed	0	0	0
Proved Undeveloped	8.4	3.7	9.0

All estimated future net cash flows are attributable to projected production from the Heidelberg Field in the U.S. Gulf of Mexico. The table below provides information regarding estimated future net cash flows (excluding derivative contracts) and the benchmark prices used.

	Estimated Future Net Cash Flows (in millions, except $ per Bbl/Mcf)	
Estimated Future Net Cash Flows	$	557.0
Standardized Measure	$	365.3
PV-10	$	365.3
Benchmark oil price ($/Bbl)	$	95.24
Benchmark natural gas price ($/Mcf)	$	4.77

Standardized Measure of Discounted Net Future Cash Flows

The standardized measure of discounted net future cash flows ("Standardized Measure") is the present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows. As of December 31, 2014, the Standardized Measure was approximately $365.0 million.

SEC reporting rules require companies to prepare reserve estimates using reserve definitions and pricing based on 12-month historical un-weighted first-day-of-the-month average prices, rather than year-end prices. Our estimated net proved reserves, future net cash flows, PV-10 and Standardized Measure were determined using index prices for oil and gas and were held constant throughout the life

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of the assets. For oil volumes, the average Light Louisiana Sweet spot price of $98.48 per barrel was used and was adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $4.35 per MMBtu was used and was adjusted for energy content, transportation fees, and a regional price differential. For the proved reserves, the average spot prices are adjusted by energy content and weighted by production over the remaining lives of the properties to determine the benchmark prices used. Such benchmark prices are $95.24 per barrel of oil and $4.77 per Mcf of gas.

PV-10

Present value of future net pre-tax cash flows attributable to our estimated net proved reserves (after deducting future development and production costs), discounted at 10% per annum ("PV-10") is a non-GAAP financial measure and is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the relative monetary significance of our properties regardless of tax structure. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our proved reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV-10 is not a substitute for the Standardized Measure. Our PV-10 and the Standardized Measure do not purport to present the fair value of our proved reserves. PV-10 is equal to the Standardized Measure as of December 31, 2014 as the tax basis in our interests in the Heidelberg Field and related net operating loss exceeds the future net cash flows (after deducting future development and production costs) and accordingly there is no tax effect on future cash flows as of December 31, 2014.

Independent Qualified Estimator

We use an Independent Qualified Estimator ("IQE") to generate and update our proved reserves. The IQE is a qualified, industry recognized, external consulting firm with extensive experience in the evaluation and estimation of reserves and resources. This approach provides us with an objective, independent assessment of the reserves which comprise our portfolio.

For the year ended December 31, 2014, we engaged NSAI to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our proved reserves and related future net cash flows.

NSAI, our independent reserve engineers, was established in 1961. Over the past 50 years, NSAI has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, acquisition and divestiture evaluations, simulation studies, exploration resources assessments, equity determinations, and management and advisory services. NSAI professionals subscribe to a code of professional conduct and NSAI is a Registered Engineering Firm in the State of Texas. NSAI is independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists and does not own an interest in our properties and is not employed on a contingent fee basis.

Internal controls over reserves estimation process

Our Reserve Evaluation Policy outlines the process and standards by which reserves are estimated, classified and reported for all our proved reserves, whether they are operated by us or operated by others. Our Chief Operating Officer Van P. Whitfield is accountable for the Reserve Evaluation Policy. Mr. Whitfield has over 39 years of experience leading oil and gas exploration and production operations activities globally. He has a Bachelor of Science Degree in Petroleum Engineering from Louisiana State University.

The Reserve Estimation Policy is administered by the Reserves Process Chair ("RPC"). The RPC is accountable for the completion of the annual and any in-year reserve estimates conducted by the

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IQE. Our Executive Vice President, Execution and Appraisal, James H. Painter acts in the role of RPC. Mr. Painter has over 34 years of experience in the oil and gas industry. Mr. Painter has a Bachelor of Science Degree in Geology from Louisiana State University.

For each reserve evaluation, a qualified technical team is established to provide data to NSAI to enable NSAI to prepare its estimate of the extent and value of the proved reserves of certain of our oil and gas properties. Our qualified technical team works with NSAI to ensure the integrity, accuracy and timeliness of data we furnish to NSAI for purposes of their reserve estimation process. Our qualified technical team has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team at a minimum holds a Bachelor of Science degree in petroleum engineering, geology or other relevant degree.

Our geotechnical, engineering and commercial inputs and interpretations required to calculate the reserves for our portfolio are compiled by our staff. This information is shared with the IQE in an open and collaborative manner, and the IQE is provided full access to complete and accurate information pertaining to the assets and to all applicable personnel. Any differences between reserve estimates internally generated by us and the IQE that exceed established threshold limits are reviewed to ensure the accuracy of the quantifiable data being used in the assessment; available data has been shared and discussed; and that methodologies and assumptions used in the estimations are clearly understood.

The NSAI technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Ruurdjan (Rudi) de Zoeten. Mr. Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (No. 73709) and has over 30 years of practical experience in petroleum engineering. He graduated from University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. de Zoeten has been practicing consulting petroleum geology at NSAI since 2008. Mr. de Zoeten is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 3179) and has over 25 years of practical experience in petroleum geosciences. He graduated from the University of Wisconsin, Madison, in 1986 with a Bachelor of Science Degree in Geology and from University of Texas at Austin in 1988 with a Master of Arts Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Our Audit Committee reviews the processes utilized in the development of our Reserve Evaluation Policy and the Reserve Report prepared by the IQE annually.

Technology used to establish proved reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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In order to establish reasonable certainty with respect to our estimated proved reserves, NSAI uses technical and economic data including, but not limited to, well logs, geologic maps, seismic data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating of and Auditing of Oil & Gas Reserves information promulgated by the Society of Petroleum Engineers (SPE Standards). They used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy and reservoir modeling that are considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. All of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions necessarily represent only informed professional judgment. See "Risk Factors—Risks Relating to Our Business—Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated."

MATERIAL AGREEMENTS

Production Sharing Contract for Block 20 Offshore Angola

On December 15, 2011, the Council of Ministers of Angola published Decree Law No. 303/11 which granted the mining rights for the prospecting, research, development and production of hydrocarbons on Block 20 offshore Angola to Sonangol, as the national concessionaire, and appointed us as the operator of Block 20. On December 20, 2011, CIE Angola Block 20 Ltd., our wholly-owned subsidiary, executed the PSC. The PSC forms the basis of our exploration, development and production operations on Block 20 offshore Angola. We are the operator of and own a 40% working interest in Block 20 offshore Angola. Currently, our paying interest on Block 20 is 57.14%, which is applicable during the exploration period. Under the PSC, we are required to drill four exploration wells (with at least one of these wells having a pre-salt objective) and acquire approximately 579 square miles (1,500 square kilometers) of 3-D seismic data all within five years of the signing of the PSC, subject to certain extensions. After this initial five year period ends, subject to any extensions, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. We have the right to a 30-year production period.

In order to guarantee these exploration work obligations under the PSC, we and BP are required to post a financial guarantee of $360 million. Our share of this financial guarantee is 57.14%, or approximately $206 million. We have delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the PSC, the amount of this letter of credit will be reduced accordingly. We acquired approximately 1,500 square kilometers of 3-D seismic data in 2012, and, accordingly, our letter of credit was reduced by approximately $17.1 million on August 16, 2012. As a result of completing drilling activities on the Lontra #1 and Orca #1 exploration wells in 2013 and 2014, respectively, our letter of credit was reduced by approximately $108.57 million on June 3, 2014. In addition, pursuant to the PSC, we and BP are required to make certain contributions for bonus, scholarships and for social projects such as the Sonangol Research and Technology Center aggregating $607.5 million, comprised of $242.5 million in the first year after the signing of the PSC, $85 million on each of the first, second and third anniversaries of the signing of the PSC, and $110 million on the fourth anniversary of the signing of the PSC. We are obligated to pay 57.14% of the foregoing costs, less $10 million previously paid, or approximately $337 million. We shall recover all exploration, development, production, administration and services expenditures incurred under the PSC by taking

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up to a maximum amount of 50% of all liquid hydrocarbons produced from Block 20. In addition, proportionate with our working interest in Block 20, we will receive 40% of a variable revenue stream that the Contractor Group (as defined in the PSC) will be allocated from Sonangol based on the Contractor Group's rate of return, reduced by applicable Angolan taxes, calculated on a quarterly basis. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 10% to 70%, and is inversely related to the applicable rate of return. Pursuant to the PSC, we do not have contractual rights to sell natural gas from Block 20, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 20.

Risk Services Agreements for Blocks 9 and 21 Offshore Angola

On June 11, 2009, the Council of Ministers of Angola published Decree Law No. 15/09 and Decree Law No. 14/09 which granted the mining rights for the prospecting, exploration, development and production of hydrocarbons on Blocks 9 and 21 offshore Angola, respectively, to Sonangol, as the national concessionaire, and appointed us as the operator of Blocks 9 and 21, respectively. On December 16, 2009, the Council of Ministers of Angola approved the terms of the finalized RSAs. On February 24, 2010, we executed RSAs for Blocks 9 and 21 offshore Angola with Sonangol, Sonangol P&P, Nazaki and Alper. Nazaki and Alper have each assigned their working interests in Blocks 9 and 21 to Sonangol P&P. The "Contractor Group" under the RSAs is currently comprised of us and Sonangol P&P. The RSAs govern our 40% working interest in and operatorship of Blocks 9 and 21 offshore Angola and form the basis of our exploration, development and production operations on these blocks.

- Under the RSA for Block 9, we are required to drill three wells, as well as acquire approximately 386 square miles (1,000 square kilometers) of seismic data within four years of its signing. This four year period may be extended by one extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the four year period and if we have otherwise fulfilled our obligations under the agreement. After this initial four or seven year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. After this initial four or seven year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. During 2014, we received a two-year extension of the initial exploration phase on Block 9 offshore Angola, and our Block 9 acreage is now scheduled to expire as of March 1, 2016. We have the right to a 20 year production period, commencing on the date of the declaration of commercial discovery for each respective development area. In order to guarantee our exploration work obligations under the RSA for Block 9, we were required to post a financial guarantee in the amount of approximately $54.7 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we complete our work obligations under the RSA, the amount of this letter of credit will be reduced accordingly. We acquired approximately 2,500 square kilometers of 3-D seismic data on Block 9 in 2011, and, accordingly, our letter of credit was reduced by approximately $9.375 million on April 25, 2011. As a result of completing drilling operations on the Loengo #1 exploration well in 2014, we submitted a request to Sonangol on October 27, 2014 to approve the reduction of our letter of credit by approximately $23.44 million. This request was approved by Sonangol on February 2, 2015 and the letter of credit was reduced accordingly on February 4, 2015. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the RSA and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 9, with Sonangol P&P holding a 60% working interest in

the block and sharing in the exploration, development and production costs associated with such block, subject to our obligation to carry a portion of Sonangol P&P's expenses through the exploration phase. Currently, our paying interest in Block 9 is 52.5%, which is applicable during the exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. Proportionate with our working interest in Block 9, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from liquid hydrocarbon production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 72% to 95%, and is inversely related to the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 55% to 95% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid). Pursuant to the RSA, we do not have contractual rights to sell natural gas from Block 9, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 9. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

- Under the RSA for Block 21, we are required to drill four wells within five years of its signing. This five year period may be extended by one extension of three years if we notify Sonangol in writing of such extension at least thirty days before the end of the five year period and if we have otherwise fulfilled our obligations under the agreement. After this initial five or eight year period ends, our rights in the block are only preserved with respect to the development areas on the block on which discoveries have been made and all other portions of the block will be forfeited. After this initial five or eight year period ends, we will also be required to commence production within four years of the date of the commercial discovery, subject to certain extensions. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We have the right to a 25 year production period, commencing on the date of the declaration of commercial discovery for each respective development area. In order to guarantee these exploration work obligations under the Risk Services Agreement for Block 21, we were required to post a financial guarantee in the amount of approximately $92.2 million. In March 2010, we delivered a letter of credit to Sonangol for such amount. As we completed our work obligations under the RSA, the amount of this letter of credit has been reduced accordingly. As a result of completing drilling operations on our Cameia #1 exploration well in 2012, our letter of credit was reduced by approximately $31.25 million on May 25, 2012. As a result of completing drilling activities on the Mavinga #1 and Bicuar #1A exploration wells in 2013, our letter of credit was reduced by approximately $40.63 million on March 12, 2014. During 2014, we completed drilling operations on our Mupa #1 exploration well, the fourth and final exploration well obligation on Block 21. We submitted a request to Sonangol on December 17, 2014 to approve the reduction of our

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letter of credit by approximately $20.3 million, thereby reducing the letter of credit balance to zero and allowing for cancellation. This request was approved by Sonangol on January 27, 2015 and the letter of credit was reduced to zero and cancelled effective February 10, 2015. As is customary in Angola, we are required to make contributions for Angolan social projects and academic scholarships for Angolan citizens. We made such an initial contribution in March 2010 after the signing of the RSA and will make additional contributions upon each commercial discovery, upon project development sanction and each year after the commencement of production. We have a 40% working interest in Block 21, with Sonangol P&P holding a 60% working interest in the block and sharing in the exploration, development and production costs associated with such block, subject to our obligation to carry a portion of Sonangol P&P's expenses through the exploration phase. Currently, our paying interest in Block 21 is 52.5%, which is applicable during the exploration period, with Sonangol P&P being obligated to pay the remaining 47.5%. Proportionate with our working interest in Block 21, we will receive 40% of a variable revenue stream that the Contractor Group will be allocated from Sonangol based on the Contractor Group's rate of return, calculated on a quarterly basis, and then reduced by applicable Angolan taxes and royalties. The Contractor Group's rate of return for each quarter will be determined by the Contractor Group's variable revenue stream from liquid hydrocarbon production less expenditures and Angolan taxes and royalties from the block. The variable revenue stream paid by Sonangol to the Contractor Group ranges from 60% to 96%, and is inversely related to the applicable rate of return. The Angolan taxes and royalties applicable to the variable revenue stream include the petroleum production tax (at a current tax rate of 20% applied to the Contractor Group's variable revenue stream), the petroleum transaction tax (at a current tax rate of 70% applied to the Contractor Group's variable revenue stream less expenditures less the Contractor Group's specified production allowance, which ranges from 35% to 90% of the Contractor Group's variable revenue stream depending inversely on the Contractor Group's rate of return) and the petroleum income tax (at a current tax rate of 65.75% applied to the Contractor Group's variable revenue stream less expenditures and less petroleum production and petroleum transaction taxes paid). Pursuant to the RSA, we do not have contractual rights to sell natural gas from Block 21, but we have the right to use the natural gas during lease and production operations. Any stand-alone gas development cannot hinder or impede the development of liquid hydrocarbons on Block 21. See "Risk Factors—Risks Relating to Our Business—Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas."

COMPETITION

The oil and gas industry is highly competitive. We encounter strong competition from other independent, major and national oil and gas companies in acquiring properties and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and gas properties, or to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of significant declines in oil and gas prices, unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position.

Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily when attempting to make future acquisitions.

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TITLE TO PROPERTY

We believe that we have satisfactory title to our prospect interests in accordance with standards generally accepted in the oil and gas industry. We currently have federal oil and gas leases in 266 blocks within the deepwater U.S. Gulf of Mexico covering approximately 1.5 million gross acres (0.8 million net acres). In West Africa, we currently have a license on the Diaba Block offshore Gabon, and licenses for Blocks 9, 20 and 21 offshore Angola covering a total of approximately 5,652,687 gross (1,840,581 net) acres. We do not have contractual rights to sell natural gas on our Angola blocks, but we have the right to use the natural gas during lease and production operations. We do, however, have contractual rights to any natural gas from our Gabon license area and all of our U.S. Gulf of Mexico leases. Our prospect interests are subject to applicable customary royalty and other interests, liens under operating agreements, liens for current taxes, and other burdens, easements, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of or affect our carrying value of the prospect interests.

CONTAINMENT RESOURCES

We are a member of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico, including the Helix Well Containment Group ("HWCG"), Clean Gulf Associates ("CGA"), the Marine Preservation Association ("MPA"), and National Response Corporation ("NRC").

We are a member of HWCG Holdings, LLC, which in turn wholly owns HWCG, LLC. HWCG, LLC serves as the operating entity for the members of HWCG by carrying out day-to-day business activities and serving as a contracting party for various oil spill and well containment equipment and services on behalf of the HWCG members. Our relationship with HWCG provides us access to the Helix Producer 1, a production handling vessel, and the Helix Q4000, a multi-purpose field intervention and construction vessel. Together with various elements of relevant hardware such as hoses, connectors, risers, and similar equipment, the Helix Producer and the Helix Q4000 form the "Helix Fast Response System". The Helix Fast Response System is currently capable of facilitating control and containment of spills in water depths up to 10,000 feet and has two capping stacks, a 15,000 psig capping stack and a 10,000 psig capping stack. The 10,000 psig capping stack is designed to have capturing and processing capabilities of 130,000 barrels of oil per day and 180 million cubic feet of gas per day. The 15,000 psig capping stack is designed to have capturing and processing capabilities of 55,000 barrels of oil per day and 100 million cubic feet of gas per day. The capping stacks are designed to handle deep, higher-pressure wells and would be used in the event a blowout preventer is ineffective. In addition to us, members of HWCG include operators such as Marathon Oil Company and Noble Energy, Inc., among others.

As a member of CGA, we have access to a large inventory of fast response oil spill recovery vessels for offshore response scenarios with remote sensing technology for locating oil slicks. In addition, the CGA fleet includes significant shoreline protection equipment and near-shore oil skimming vessels.

As a member of MPA, we have access to the resources of the Marine Spill Response Corporation ("MSRC"). MSRC provides a wide variety of surface spill equipment, including a deepwater response fleet, aerial dispersant fleet, and approximately 75% of the existing dispersant material in the U.S. Gulf of Mexico region. NRC is an umbrella response corporation that provides us access to a wide variety of surface spill response equipment as well as a wide group of surface response contractors that can address a surface response as well as play a support role in addressing a subsea well containment event. In addition, we have existing contracts with a number of contractors which have equipment that could assist in well containment efforts as well as with the surface effects of a subsea blowout or in addressing a concurrent surface spill. Examples of such equipment include, but are not limited to,

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anchor and supply vessels, subsea transponders and communication equipment, subsea cutting equipment, debris removal equipment, air and water monitoring and scientific support vessels, remote-operated vehicles, storage and shuttle vessels, and subsea dispersant equipment.

For our operations offshore West Africa, we have contracts in place with Wild Well Control which provide for subsea well control planning, response management, and access to a 15,000 psig capping stack system, subsea debris removal equipment package, and subsea dispersant application equipment in air freight configuration for mobilization to Angola. We also have contracts in place for the provision of oil spill management, equipment and response services. Specifically, we have contracted with (i) Braemer-Howells, a U.K.-based company with staff in Angola, which provides us access to oil spill response management, equipment and services, (ii) the West and Central African Aerial Surveillance and Dispersant Service, a non-profit organization which provides aerial surveillance and chemical dispersant services offshore Angola utilizing aircraft based in Ghana, and (iii) Oil Spill Response Limited, a U.K.-based company which is wholly owned by exploration and production companies and provides us access to personnel and equipment for oil spill events. We have also developed an Oil Spill Response Plan to address any potential spill, and we have access to equipment which is pre-staged in Angola, including containment boom, skimming systems, chemical dispersant systems, and temporary oil storage systems.

Furthermore, we also have contracts in place with Witt-O'Brien's, The Response Group and J. Connor Consulting for the provision of additional emergency response management services to help us address an incident in either the U.S. Gulf of Mexico or West Africa.

We are also members of the Oil Spill Response, Ltd. Global Dispersant Stockpile. This membership provides us access to a supply of over 1 million gallons of dispersant for use in a subsea well control event. This stockpile is stored in six locations around the world in portable containers ready for air freight transport.

In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors —Risks Relating to Our Business—We are subject to drilling and other operational hazards."

INSURANCE COVERAGE

For our U.S. Gulf of Mexico operations, we purchase insurance limits including a $650 million policy for operator's extra expense, which includes coverage for well control losses, re-drill and pollution clean-up expenses, $450 million of aggregated limits for third-party liability losses including coverage for bodily injury or death and property damage as well as seepage and clean-up of pollution on a sudden and accidental basis, and a $45 million policy for pollution damages as defined under the Oil Pollution Act of 1990 ("OPA"). In addition, we have identified certain of our unencumbered assets in the U.S. Gulf of Mexico to demonstrate $105 million of Oil Spill Financial Responsibility ("OSFR") through self-insurance to the Bureau of Ocean Energy Management ("BOEM") as permitted under the OPA. Towards the end of 2013, we also purchased insurance coverage for our working interest related to construction for our only U.S. Gulf of Mexico sanctioned development project, the Anadarko operated Heidelberg field development.

For our West Africa operations, we purchase operator's extra expense insurance with limits per well of the greater of three times the amount of our nominal dry-hole authorization-for-expenditure for each well or approximately $350 to $400 million. In addition, we also purchase $50 million of third-party liability insurance coverage specifically for liabilities arising out of our Angolan operations. Upon anticipated sanction of our operated Cameia field development project, we plan to purchase insurance coverage associated with those construction risks.

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In general, our current insurance policies cover physical damage to our oil and gas assets. The coverage is designed to repair or replace assets damaged by insurable events. Certain of our stated insurance limits scale down to our working interest in the prospect being drilled, including coverage for well control losses, re-drill and pollution clean-up expenses and certain excess third-party liability coverage. All insurance recovery is subject to various deductibles or retentions as well as specific terms, conditions and exclusions associated with each individual policy. We believe that our coverage limits are sufficient and are consistent with what is held by our peers operating in the deepwater U.S. Gulf of Mexico and West Africa. However, there is no assurance that such coverage will adequately protect us against liability and loss from all potential consequences and damages associated with losses, should they occur. In considering the information above, specific reference should be made to the subsection of this Annual Report on Form 10-K titled "Risk Factors—Risks Relating to Our Business—We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage" and "Risk Factors—Risks Relating to Our Business—We are subject to drilling and other operational hazards."

ENVIRONMENTAL MATTERS AND REGULATION

General

We are, and our future operations will be, subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use, transportation and disposal of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- enjoin some or all of the operations of facilities deemed not in compliance with such laws and regulations or permits issued thereunder;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas exploration, drilling, production and transportation activities;
- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate or address pollution from our operations.

These laws, regulations and permits may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws, regulations and permits can be costly; the regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Moreover, particularly in light of the Deepwater Horizon incident in the U.S. Gulf of Mexico, public interest in the protection of the environment and human health has increased. Offshore drilling in some areas has been opposed by environmental groups and, in other areas, has been restricted. Our operations could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that result in increased costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal, cleanup requirements or financial responsibility and assurance requirements.

Accidental spills or releases may occur in the course of our operations, and we cannot assure you that we will not incur substantial costs and liabilities as a result, including costs relating to claims arising from damage to natural resources, property and persons. Moreover, environmental laws and regulations are complex, change frequently and have tended to become more stringent over time.

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Accordingly, we cannot assure you that we have been or will be at all times in compliance with such laws and regulations, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the existing laws or regulatory issues to which we and our business operations are or may be subject to in the future.

Impact of the 2010 U.S. Gulf of Mexico Oil Spill

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the U.S. Department of the Interior ("DOI") and two of its agencies, the BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE"), which together formerly comprised the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), responded to this incident by imposing moratoria on drilling operations. These agencies adopted numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico that are applicable to us and with which our new applications for exploration plans and drilling permits must prove compliant. These regulations include (i) the Increased Safety Measures for Energy Development on the Outer Continental Shelf—Final Rule, which sets forth increased safety measures for offshore energy development and requires, among other things, that all offshore operators submit written certifications as to compliance with the rules and regulations for operations occurring in the Outer Continental Shelf including the submission of independent third party written certifications as to the capabilities of certain safety devices, such as blowout preventers and their components, (ii) the Workplace Safety Rule, which requires operators to develop and implement a comprehensive Safety and Environmental Management System, or SEMS, for oil and gas operations and codifies and makes mandatory the American Petroleum Institute's Recommended Practice 75, (iii) NTL No 2010-N06, which sets forth requirements for exploration plans, development and production plans and development operations coordination documents to include a blowout scenario, the assumptions and calculations that are used to determine the volume of the worst case discharge scenario, and proposed measures to prevent and mitigate a blowout and (iv) NTL No. 2010-N10, which requires that each operator submit adequate information demonstrating that it has access to and can deploy containment resources that would be adequate to promptly respond to a blowout or other loss of well control, adds additional requirements to oil spill response plans and requires that operators submit written certifications stating that the operator will conduct all authorized activities in compliance with all applicable regulations. While we conducted our own internal SEMS assessment and conducted a third party SEMS audit in 2013 to ensure we are in compliance with all applicable regulations related to our SEMS, effective June 4, 2013, the so-called SEMS II Rule amended the Work Place Safety rule to include additional safety requirements. Operators, including us, are now required to comply with the SEMS II Rule, and have an independent audit completed by June 4, 2015. In addition, the BSEE has proposed revisions to 30 CFR 250, subpart H on Oil and Gas Production Safety Systems to address recent technological advances in production safety systems and equipment used to collect and treat oil and gas from Outer Continental Shelf leases. This includes among other things, certain standards concerning the use of best available and safest technology, more rigorous design and testing requirements for boarding shut down valves, and an increase in approved leakage rates for certain safety valves. When finalized, these and any additional new regulations may result in delays in the permitting process.

Compliance with new and existing regulations and the interpretations of them may materially increase the cost of and time required to obtain drilling permits or conduct our drilling operations in

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the U.S. Gulf of Mexico, which may adversely affect our business, financial position or future results of operations.

Oil Pollution Act of 1990

The OPA and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters or in the exclusive economic zone of the U.S. Liability under the OPA is strict, joint and several and potentially unlimited. A "responsible party" under the OPA includes the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility to cover potential liabilities related to an oil spill for which such person would be statutorily responsible in an amount that depends on the risk represented by the quantity or quality of oil handled by such facility. The BSEE has promulgated regulations that implement the financial responsibility requirements of the OPA. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil, administrative and/or criminal enforcement actions. There has also been a call from public interest groups, certain governmental officials and, in 2011, the National Commission on the BP Deepwater Horizon Spill and Offshore Drilling for, among other things, increased government oversight of the offshore oil and gas industry, to require more comprehensive financial assurance requirements, to raise or eliminate the economic damages liability cap under OPA, significantly raise daily penalties for OPA infractions and make the environmental review process more stringent. If adopted, certain of these proposals have the potential to adversely affect our operations by restricting areas in which we may carry out exploration or development activities and/or causing us to incur increased operating expenses or liabilities. To satisfy OPA's requirement that we demonstrate at least $150 million of Oil Spill Financial Responsibility, we have (i) identified certain unencumbered assets in the U.S. Gulf of Mexico to the BOEM to demonstrate $105 million of Oil Spill Financial Responsibility through self-insurance, and (ii) procured the remaining $45 million of Oil Spill Financial Responsibility through third party insurance coverage.

Clean Water Act

The U.S. Federal Water Pollution Control Act of 1972, or Clean Water Act, as amended ("CWA"), imposes restrictions and controls on the discharge of pollutants, produced waters and other oil and natural gas wastes into waters of the U.S. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Under the CWA, permits must be obtained to discharge pollutants into regulated waters. In addition, certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up related damage and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

Marine Protected Areas

Executive Order 13158, issued in 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the U.S. and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the U.S. Environmental Protection Agency ("EPA") to propose regulations under the CWA to ensure appropriate levels of protection for the marine environment. This order and related CWA

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regulations have the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Consideration of Environmental Issues in Connection with Governmental Approvals

Our operations frequently require licenses, permits and other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA"), and the Coastal Zone Management Act ("CZMA") require federal agencies to evaluate environmental issues in connection with granting such approvals or taking other major agency actions. OCSLA, for instance, requires the DOI to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment, and gives the DOI authority to refuse to issue, suspend or revoke permits and licenses allowing such activities in certain circumstances, including when there is a threat of serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency must prepare an environmental assessment and, potentially, an environmental impact statement. If such NEPA documents are required, the preparation of such could significantly delay the permitting process and involve increased costs. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we will have to certify that we will conduct our activities in a manner consistent with any applicable CZMA program. Violation of these foregoing requirements may result in civil, administrative or criminal penalties.

Naturally Occurring Radioactive Materials

Wastes containing naturally occurring radioactive materials ("NORM") may also be generated in connection with our operations. Certain oil and natural gas exploration and production activities may enhance the radioactivity, or the concentration, of NORM. In the U.S., NORM is subject to regulation primarily under individual state radiation control regulations. In addition, NORM handling and management activities are governed by regulations promulgated by the Occupational Safety and Health Administration. These regulations impose certain requirements concerning worker protection; the treatment, storage and disposal of NORM waste; the management of waste piles, containers and tanks containing NORM; and restrictions on the uses of land with NORM contamination.

Resource Conservation and Recovery Act

The U.S. Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently exempt from RCRA's requirements pertaining to hazardous waste and are regulated under RCRA's non-hazardous waste and other regulatory provisions. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Accordingly, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we expect to

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generate some amounts of ordinary industrial wastes, such as waste solvents and waste oils, which may be regulated as hazardous wastes.

Air Pollution Control

The U.S. Clean Air Act, as amended ("CAA") and state air pollution laws adopted to fulfill its mandates provide a framework for national, state, regional and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to the CAA and other pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA or other air pollution laws and regulations, including the suspension or termination of permits and monetary fines. Recently, the EPA also proposed new air regulations for oil and gas exploration, production, transmission and storage. These include new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and air toxics standards issued in April 2012 and updated VOC performance standards for storage tanks used in crude oil and natural gas production and transmission issued in August 2013. These regulations could require us to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements.

Superfund

The U.S. Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), also known as "Superfund," imposes joint and several liability for response costs at certain contaminated properties and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or past owner or operator of the site where the release occurred and anyone who transported, disposed or arranged for the disposal of a hazardous substance at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur and seek natural resource damages.

Protected Species and Habitats

The U.S. federal Endangered Species Act, the federal Marine Mammal Protection Act, and similar federal and state wildlife protection laws prohibit or restrict activities that could adversely impact protected plant and animal species or habitats. Oil and natural gas exploration and production activities could be prohibited or delayed in areas where protected species or habitats may be located, or expensive mitigation may be required to accommodate such activities.

Climate Change

Our operations and the combustion of petroleum and natural gas-based products results in the emission of greenhouse gases ("GHG") that could contribute to global climate change. Climate change regulation has gained momentum in recent years internationally and domestically at the federal, regional, state and local levels. Various U.S. regions and states have already adopted binding climate change legislation. In addition, the U.S. Congress has at times considered the passage of laws to limit the emission of GHGs. It is possible that federal legislation related to GHG emissions will be considered by Congress in the future.

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The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The EPA has issued final and proposed regulations pursuant to the CAA to limit carbon dioxide and other GHG emissions. Pursuant to the EPA's "Mandatory Reporting of Greenhouse Gases" final rule ("GHG Reporting Rule"), operators of stationary sources emitting more than established annual thresholds of carbon dioxide equivalent GHGs, as well as certain oil and natural gas facilities, including certain producers and offshore exploration and production operations, must inventory and report their GHG emissions annually. The EPA also regulates GHG emissions from certain stationary sources under regulations formerly known as the Tailoring Rule. In June 2013, the Obama Administration released its Climate Action Plan ("CAP") that, among other things, calls upon the EPA to promulgate greenhouse gas regulations for new and existing power plants. In 2014, the EPA issued these proposals which are expected to be finalized by summer 2015. The EPA is also required pursuant to a settlement agreement to issue GHG emissions standards for oil refineries, but no such standards have been proposed to date. In addition, the CAP calls upon EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. On January 14, 2015, the White House unveiled these plans which, among other things directs the EPA to propose rules to regulate methane emissions from the oil and gas industry from new and modified sources by summer 2015, with a finalized rule in 2016. The EPA is also directed to expand the GHG Reporting Rule to cover all segments of the oil and gas industry. Additionally, in April 2010 and August 2012, the EPA and the National Highway Traffic Safety Administration finalized GHG emissions standards for light duty vehicles for model years 2012 through 2016 and 2017 through 2025, respectively. In August 2011, these two agencies also announced national efficiency and emissions standards for medium and heavy duty engines and vehicles. Each of these pending, proposed and future laws, regulations and initiatives could adversely affect us directly as well as indirectly, as they could decrease the demand for oil and natural gas.

On the international level, various nations, including Angola and Gabon, have committed to reducing their GHG emissions pursuant to the Kyoto Protocol. The Kyoto Protocol was set to expire in 2012. In late 2011, an international climate change conference in Durban, South Africa resulted in, among other things, an agreement to negotiate a new climate change regime by 2015 that would aim to cover all major greenhouse gas emitters worldwide, including the U.S., and take effect by 2020. In November and December 2012, at an international meeting held in Doha, Qatar, the Kyoto Protocol was extended by amendment until 2020. In addition, the Durban agreement to develop the protocol's successor by 2015 and implement it by 2020 was reinforced at a November 2013 international climate change conference in Warsaw, Poland. The next international meeting is scheduled for December 2015 in Paris, France. U.S. federal climate change legislation or regulation or climate change legislation or regulation in other regions in which we conduct business could have an adverse effect on our results of operations, financial condition and demand for oil and natural gas.

Health and Safety

Our operations are subject to the requirements of the federal U.S. Occupational Safety and Health Act ("OSH Act") and comparable foreign and state statutes. These laws and their implementing regulations strictly govern the protection of the health and safety of employees. In particular, the OSH Act hazard communication standard, EPA community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act of 1986 and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require us to ensure our workplaces meet minimum safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances.

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Other Regulation of the Oil and Gas Industry

The oil and gas industry is regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase our cost of doing business by increasing the future cost of transporting our production to market, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Homeland Security Regulations

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and natural gas facilities that are deemed to present "high levels of security risk." The DHS is currently in the process of adopting regulations that will determine whether our operations may in the future be subject to DHS-mandated security requirements. Presently, it is not possible to accurately estimate the costs we could incur, directly or indirectly, to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and Production

Development and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. U.S. laws under which we operate may also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

Regulation of Transportation and Sale of Natural Gas

The availability, terms and cost of transportation significantly affect sales of natural gas. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. The FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. Upon us reaching the production stage of our business model, such regulations will be applicable to us.

Although gas prices are currently unregulated, Congress historically has been active in the area of gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

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U.S. Coast Guard and the U.S. Customs Service

The transportation of drilling rigs to the sites of our prospects in the U.S. Gulf of Mexico and our operation of such drilling rigs is subject to the rules and regulations of the U.S. Coast Guard and the U.S. Customs Service. Such regulation sets safety standards, authorizes investigations into vessel operations and accidents and governs the passage of vessels into U.S. territory. We are required by these agencies to obtain various permits, licenses and certificates with respect to our operations.

Laws and Regulations of Angola and Gabon

Our exploration and production activities offshore Angola and Gabon are subject to Angolan and Gabonese regulations, respectively. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following are summaries of certain applicable regulatory frameworks in Angola and Gabon.

Angola

In Angola, petroleum exploration and development activities are governed by the Petroleum Activities Law (the "Angola PAL"). Pursuant to the Angola PAL, all hydrocarbons located underground are property of the State of Angola, and exploitation rights can only be granted by the President of the Republic to Sonangol, as the national concessionaire. Foreign companies may only engage in petroleum activities in Angola in association with Sonangol through a commercial company or consortium, and generally upon entering a production sharing contract or a risk services agreement.

The Angolan PAL and the regulations thereunder extensively regulate the activities of oil and gas companies operating in Angola, including financial and insurance requirements, local content and involvement requirements, exploration and development processes, and operational matters. Local content regulations stipulate which goods or services relating to the oil and gas industry must be provided by Angolan companies (being companies which are beneficially owned in their majority by Angolan citizens), whether on a sole basis or in association with foreign contractors, and which goods or services may be provided by foreign companies. Goods or services which may be provided by foreign companies are generally subject to a local preference rule, whereby Angolan companies are granted preference in tendering for such activities or services, provided that the price difference in such tender does not exceed 10% of the total tendered amount. The power to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, is vested with Sonangol.

The petroleum agreements entered with Sonangol set forth the main provisions for exploration and production activities, including fiscal terms, mandatory State participation, obligations to meet domestic supply requirements, local training and spending obligations, and ownership of assets used in petroleum operations. Angolan law and these agreements also contain important limitations on assignment of interests in such licenses, including in most cases the need to obtain the consent of Angolan authorities.

Certain industry-specific and general application statutes and regulations govern health, safety and environmental matters under Angolan law. Prior to commencing petroleum operations in Angola, contractors must, among other things, prepare an environmental impact assessment and establish and implement a health and safety plan. Such environmental laws govern the disposal of by-products from petroleum operations and required oil spill preparedness capabilities. Failure to comply with these laws may result in civil and criminal liability, including, without limitation, fines or penalties.

Angola enacted the Foreign Exchange Law for the Petroleum Sector in 2012, Law N° 2/12, of January 13, 2012, which requires, among other things, that all foreign exchange operations be carried

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out through Angolan banks, that oil and gas companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. As a consequence, foreign currency proceeds obtained by oil and gas companies from the sale of their share of production cannot be retained in full outside Angola, as a portion of the proceeds required to settle tax liabilities and pay for local petroleum operations-related expenses must be deposited in and paid through Angolan banks. Furthermore, oil and gas companies are required to convert funds into local currency and deposit such funds in local bank accounts in order to pay for local petroleum operations-related expenses. The Foreign Exchange Law for the Petroleum Sector was further supplemented by Banco Nacional de Angola's Order 20/2012, of April 25, 2012, which details the procedures and mechanisms that must be adopted by oil and gas companies and sets forth a schedule for their phased implementation. Under this statute, since October 1, 2012, oil companies (including operators) are required to make all payments for goods and services supplied by foreign exchange residents (as defined in the Foreign Exchange Law) out of bank accounts domiciled in Angola, whether in national or foreign currency. As of July 1, 2013, oil and gas exploration and production companies (including operators) are now required to make all payments for goods and services provided by foreign exchange residents in local currency. From October 1, 2013 onwards, operators are required to make all payments for goods and services related to Angolan operations provided by non-residents out of bank accounts domiciled in Angola. Banco Nacional de Angola (BNA) has recently issued Order 7/14, of October 8, 2014 which determines that oil companies shall sell to BNA the foreign currency required to pay taxes and other tax dues before the State. The operators shall also sell to BNA the foreign currency necessary to pay foreign exchange residents.

On October 8, 2013, Angola enacted Executive Decree 333/13 ("ED 333/13") which enforces a consumption tax on oil companies. ED 333/13 requires companies that provide taxable services to oil companies to assess the applicable consumption tax, and oil companies, as beneficiary of those services, must pay the net value of the service to the service provider and remit the consumption tax to the Angolan government. The services that are subject to the consumption tax include, but are not limited to, consultancy services, supply of energy, water and telecommunications, leasing of machines and other equipment, private security services and travel services. The applicable consumption tax rates are 5% or 10% of the value of the services depending on the nature of the service rendered.

On October 21, 2014, Angola published Presidential Legislative Decree no. 3-A/14 which repealed ED 333/13. This new statute provides that there will be no consumption tax applicable to the petroleum companies which are in the exploration and development phases and until first oil, subject to certain exceptions. Subject to the approval of the Ministry of Finance and Sonangol, petroleum companies may also benefit from the consumption tax exemption during the production phase should those companies demonstrate that the consumption tax causes imbalances which render the petroleum projects not economically viable.

Executive Decree no. 224/12 of 16 July approved the Operational Discharge Management Regulations. This statute applies to all operational discharges generated during petroleum operations, both onshore and offshore. It sets the zero discharge prohibition establishing that all operational discharges resulting from onshore activities into the ground, inland waters and coastal waters are prohibited, except where duly justified for safety reasons. Discharges of (i) drill cuttings contaminated with non-water based drilling muds; (ii) non-water based drilling fluids; and (iii) sands produced resulting from operations in the maritime zone are prohibited and must be brought to shore and be treated as hazardous waste. This statute requires operators such as ourselves to prepare an Operational Discharge Management Plan for all facilities or groups of facilities under its responsibility. The statute also establishes that the direct discharge of chemical products into the sea and the use of compounds where the content in aromatics is greater than 1% (one percent) as a base for the manufacture of

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drilling fluids are prohibited. On April 8, 2014, Executive Decree no. 97/14 was published in the Angolan official gazette. This statute approved a moratorium on the implementation of the above mentioned regulations. Petroleum companies operating existing deep and ultra-deep water facilities now have until July 8, 2015 to implement these regulations.

See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

Gabon

In 2014, a new Hydrocarbons Law entered into force to regulate oil and gas activities in Gabon. It has repealed some prior laws relating to oil activities as well as all contradictory regulations contained in the remaining non-repealed laws of the oil and gas sector.

Pursuant to the Hydrocarbons Law, petroleum resources in Gabon are the property of the State of Gabon and petroleum companies undertake operations on behalf of the Government of Gabon. In order to conduct petroleum operations, oil and gas companies must enter into a hydrocarbons agreement, typically an exploration and production sharing contract ("EPSC"), with the Minister of Hydrocarbons and the Minister of Economy. Such agreement is subject to enactment by Presidential Decree, and its provisions must conform to the Hydrocarbons Law, subject to being null and void.

Furthermore, all oil companies, even those carrying out operations under the previous legal framework, must make payment of two financial contributions set forth in the new Hydrocarbons Law, namely the Investment Diversification Fund (payment of 1% of the Contractor's turnover during the production phase), and the Hydrocarbons Investment Fund (payment of 2% of the Contractor's turnover during the production phase), within two years of the entry into force thereof. Oil companies must also, within a maximum of one year from publication of the Hydrocarbons Law, set up and domicile the site rehabilitation funds for the Hydrocarbon activities ("*Fonds RES*") at the *Banque des Etats de l'Afrique Centrale* or at a Gabonese banking or financial institution.

The Hydrocarbons Law provides for a detailed legal framework in terms of organization of the sector, contents and terms and conditions of hydrocarbons agreements, liability, local content, safety and environment, domestic supply requirements, fiscal terms such as production sharing, royalty, bonuses and other charges, corporate income tax, customs, and local training obligations.

The powers to make many of the day-to-day decisions concerning petroleum activities, including the granting of certain consents and authorizations, remain vested with the Hydrocarbons General Directorate, a government authority. In addition, the national oil company—*Société Nationale des Hydrocarbures du Gabon*—currently holds, manages and takes participations in petroleum activities on behalf of the State. Pursuant to the Hydrocarbons Law, the State may acquire an equity stake of up to 20%, at market value, within any companies applying for or already holding an exclusive production authorization. The contractor must carry the State in its 20% participating interest in the hydrocarbons agreements during the exploration phase. The parties are free to agree on a higher stake at market value. Further, the national oil company may also acquire participating interests of up to 15%, at market value.

In addition to general local content regulations which require a 90/10 ratio of Gabon national to foreign expatriate workers involved in petroleum activities, pursuant to the Hydrocarbons Law, subcontracting activities are awarded in priority to Gabonese companies in which more than 80% of the workforce consists of Gabonese nationals. In this respect, only technically qualified license holders may be hired as subcontractors.

Assignment of interests is subject to the Ministry of Hydrocarbons' consent. Foreign companies carrying out production activities under the form of a local branch must incorporate a local company within 2 years of entry into force of the Hydrocarbons Law.

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With respect to gas, the State shall enjoy exclusive marketing rights for non-associated gas while any non-commercial share of associated gas remains the property of the State.

Hydrocarbons agreements entered into prior to the Hydrocarbon Law's publication remain in force and should continue to be governed by their own provisions. Our understanding is that the Hydrocarbons Law applies to any issues not expressly dealt with in these contracts' provisions.

Our EPSC governing our license to the Diaba block offshore Gabon was entered into before the publication of the Hydrocarbon Law. The Diaba EPSC contains a stabilization clause, which provides for the stability of the legal, tax, economic and financial conditions in force at the signing of the EPSC. Pursuant to the Diaba EPSC, these conditions may not be adversely altered during the term of the agreement, however, we can make no assurance that the Hydrocarbon Law will not adversely affect our operations or assets in Gabon. See "Risk Factors—Risks Related to Our Business—Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business."

EMPLOYEES

As of December 31, 2014, we had 205 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory. In addition, as of December 31, 2014, we had 150 contractors, consultants and secondees working in our offices and field locations.

CORPORATE INFORMATION

We were incorporated pursuant to the laws of the State of Delaware as Cobalt International Energy, Inc. in August 2009 to become a holding company for Cobalt International Energy, L.P. Cobalt International Energy, L.P. was formed as a limited partnership on November 10, 2005 pursuant to the laws of the State of Delaware. Pursuant to the terms of a corporate reorganization that we completed in connection with our initial public offering, all of the interests in Cobalt International Energy, L.P. were exchanged for common stock of Cobalt International Energy, Inc. and, as a result, Cobalt International Energy, L.P. is wholly-owned by Cobalt International Energy, Inc.

AVAILABLE INFORMATION

We make certain filings with the SEC, including our Annual Report on Form 10-K, proxy statements, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.cobaltintl.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 between the hours of 10 a.m. and 3 p.m. on official business days or by calling 1-800-SEC-0330 for further information on the operation of the Public Reference Room. Also, these filings are available on the internet at http://www.sec.gov. Our press releases and recent analyst presentations are also available on our website. The information on our website does not constitute a part of this Annual Report on Form 10-K and shall not be deemed to be a part hereof or incorporated into this or any our filings with the SEC.

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EXECUTIVE OFFICERS

The following table sets forth certain information concerning our executive officers as of the date of this Annual Report.

Name	Age	Position
Joseph H. Bryant	59	Chairman of the Board of Directors and Chief Executive Officer
Van P. Whitfield	63	Chief Operating Officer and Executive Vice President
John P. Wilkirson	57	Chief Financial Officer and Executive Vice President
James H. Painter	57	Executive Vice President
James W. Farnsworth	59	Chief Exploration Officer and Executive Vice President
Shashank V. Karve	59	Executive Vice President, Projects
Jeffrey A. Starzec	38	Executive Vice President and General Counsel
Richard A. Smith	55	Senior Vice President
Lynne L. Hackedorn	56	Vice President, Government and Public Affairs

Biographical Information

Joseph H. Bryant has served as Chief Executive Officer and Chairman of our Board of Directors since our inception in November 2005. Mr. Bryant has 36 years of experience in the oil and gas industry. Prior to joining Cobalt, from September 2004 to September 2005, he was President and Chief Operating Officer of Unocal Corporation, an oil and gas exploration and production company. From May 2000 to August 2004, Mr. Bryant was President of BP Exploration (Angola) Limited, from January 1997 to May 2000, Mr. Bryant was President of BP Canada Energy Company (including serving as President of Amoco Canada Petroleum Co. between January 1997 and May 2000, prior to its merger with BP Canada), and from 1993 to 1996, Mr. Bryant served as President of a joint venture between Amoco Orient Petroleum Company and the China National Offshore Oil Corporation focused on developing the offshore Liuhua fields. Prior to 1993, Mr. Bryant held executive leadership positions in Amoco Production Company's business units in The Netherlands and the Gulf of Mexico, serving in many executive capacities and in numerous engineering, financial and operational roles throughout the continental United States. Mr. Bryant served on the board of directors of Berry Petroleum Company from October 2005 until May 2011. Mr. Bryant currently also serves on the board of directors of the American Petroleum Institute. Mr. Bryant holds a Bachelor of Science in Mechanical Engineering from the University of Nebraska.

Van P. Whitfield has served as Chief Operating Officer and Executive Vice President since September 2011. Mr. Whitfield served as our Executive Vice President, Operations and Development from May 2006 until September 2011. Mr. Whitfield has over 39 years of experience leading oil and gas production operations and marketing activities in North America, the United Kingdom and Europe, the Middle East and Asia. Prior to joining Cobalt, from May 2003 to May 2005, Mr. Whitfield served as Senior Vice President, Western Operations of CDX Gas LLC, an independent oil and gas company. From October 2002 to April 2003 he served as Production Unit Leader for the Angola Liquid Natural Gas Project, BP Exploration (Angola) Limited and from June 2001 to October 2002, he held the position of Vice President, Power and Water of ExxonMobil Saudi Arabia (Southern Ghawar) Ltd, an exploration and production company. Mr. Whitfield has also held the positions of Senior Vice President of BP Global Power, President and General Manager of Amoco Netherlands BV and Production Manager of Amoco (U.K.) Exploration Company, both exploration and production companies. In addition, he has held numerous operational and technical leadership positions in various Amoco Production Company locations, including: the position of Production Manager, West Texas and Engineering Manager, Worldwide. Mr. Whitfield has a Bachelor of Science Degree—Petroleum Engineering from Louisiana State University and is a graduate of the Executive Program at Stanford University.

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John P. Wilkirson has served as Executive Vice President and Chief Financial Officer since June 2010. From 2007 until June 2010, Mr. Wilkirson served as our Vice President, Strategic Planning and Investor Relations. Mr. Wilkirson has 33 years of experience in the energy industry. Prior to joining Cobalt, from 1998 to 2005, Mr. Wilkirson was Vice President, Strategic Planning and Economics of Unocal Corporation, where his primary responsibilities included identifying and addressing major strategic issues, managing the global asset and investment portfolio, leading the economic analysis and evaluations function and overseeing performance management. He played an instrumental role as the integration executive for Unocal Corporation's merger into Chevron Corporation. Prior to Unocal Corporation, from 1992 to 1997, Mr. Wilkirson was an Engagement Manager at McKinsey & Company, Inc., a management consulting firm, serving energy clients on strategy and performance improvement engagements. Additional industry experience includes positions at Exxon Company USA from 1980 to 1984 and Sohio Petroleum Company and BP from 1984 to 1991, in petroleum engineering and commercial assignments. Mr. Wilkirson has a Bachelor of Science with Highest Honors in Petroleum Engineering and a Master of Business Administration from the University of Texas at Austin.

James H. Painter has served as Executive Vice President since April 2013. Mr. Painter previously served as our Executive Vice President, Gulf of Mexico from our inception in November 2005 until April 2013. Mr. Painter has more than 34 years of experience in the oil and gas industry. Prior to joining Cobalt, from February 2004 to September 2005, Mr. Painter was the Senior Vice President of Exploration and Technology at Unocal Corporation. Prior to his position at Unocal Corporation (following the merger between Ocean Energy Inc. and Devon Energy Corporation), from April 2003 to October 2003, Mr. Painter served as the Vice President of Exploration at Devon Energy Corporation, an oil and gas exploration and production company. From January 1995 to April 2003, Mr. Painter served in various manager and executive positions at Ocean Energy Inc. (and its predecessor Flores and Rucks, Inc.) with his final position as Senior Vice President of Gulf of Mexico and International Exploration. Additional industry experience includes positions at Forest Oil Corporation, an independent oil and gas exploration and production company, Mobil Oil Corporation and Superior Oil Company, Inc. Mr. Painter holds a Bachelor of Science in Geology from Louisiana State University.

James W. Farnsworth has served as our Chief Exploration Officer and Executive Vice President since April 2013. Mr. Farnsworth previously served as Chief Exploration Officer from our inception in November 2005 until April 2013. Mr. Farnsworth has had more than 33 years of experience in the oil and gas industry. From 2003 to 2005, Mr. Farnsworth held the position of Vice President of World-Wide Exploration and Technology, at BP p.l.c., a global energy company, responsible for BP p.l.c.'s global exploration business inclusive of North America, West Africa, North Africa, South America, Russia and the Far East. His prior positions at BP p.l.c., from 1983 to 2003, include: Vice President of North America Exploration; Vice President of Gulf of Mexico Exploration; Exploration Manager for Alaska; Deepwater Gulf of Mexico Production Manager for non-operated fields. Mr. Farnsworth has a Bachelor of Science Degree in Geology from Indiana University and a Masters of Science Degree in Geophysics from Western Michigan University.

Shashank V. Karve joined Cobalt in December 2014 and currently serves as our Executive Vice President, Projects. Mr. Karve has over 30 years of experience managing and executing large scale offshore oil and gas developments. Prior to joining Cobalt, from September 2011 to December 2014, Mr. Karve was President and CEO of Seanergis Management Services, a company he co-founded to offer area wide upstream and midstream infrastructure to the oil and gas industry. From 2009 until May 2011, Mr. Karve held the positions of Managing Director and Chief Operating Officer of MODEC, Inc. and Chairman and CEO of MODEC International Inc., a global provider of floating production, storage, and offloading (FPSO) vessels and other offshore oil and gas infrastructure. During this time, Mr. Karve was responsible for the on-time delivery of the first FPSOs on the pre-salt Lula field offshore Brazil and the Jubilee field offshore Ghana. From 2001 to 2008, Mr. Karve served

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as President and CEO of MODEC International LLC, where he oversaw MODEC's entry into the Brazilian and Angolan FPSO markets. Prior to that, Mr. Karve held several senior managerial positions with MODEC International LLC, including serving as Chief Operating Officer from 1997 to 2001. Mr. Karve received a graduate degree in Ocean Engineering from the Massachusetts Institute of Technology and a bachelor's degree in Naval Architecture and Marine Engineering from the Indian Institute of Technology.

Jeffrey A. Starzec has served as Executive Vice President and General Counsel since February 2015. Mr. Starzec also serves as our Corporate Secretary. Mr. Starzec served as our Senior Vice President and General Counsel from January 2012 to February 2015. From June 2009 until December 2011, Mr. Starzec served as our Associate General Counsel and Corporate Secretary. Prior to joining Cobalt, Mr. Starzec practiced corporate and securities law at Vinson & Elkins LLP from July 2006 until June 2009, where he represented a variety of energy companies, including Cobalt in connection with its strategic alliance with Total in the U.S. Gulf of Mexico. Mr. Starzec began his legal career at Baker Botts LLP and holds a Bachelor of Science in Economics from Duke University and a J.D. from Harvard Law School.

Richard A. Smith has served as Senior Vice President since September 2014. Prior to holding this position, Mr. Smith served as Senior Vice President and President of Cobalt Angola from November 2013 to September 2014. Mr. Smith served as Vice President, Investor Relations, Compliance and Risk Management from December 2012 until November 2013. Before that, Mr. Smith served as Vice President, Investor Relations and Planning from October 2011 until December 2012. Mr. Smith served as Vice President, International Business Development, Commercial and Finance from September 2010 until October 2011. From October 2007 until September 2010, Mr. Smith served as our Vice President. Mr. Smith has over 32 years of oil and gas industry experience in North American and international markets. Prior to joining Cobalt, from September 2005 to September 2007, Mr. Smith was Vice President, Joint Venture Development Corporate Affairs for the BP Russia Offshore Strategic Performance Unit, an oil and gas exploration and production unit of BP. From February 2002 to August 2005, he held the position of Vice President and then Executive Director for BP Exploration (Angola) Limited, an oil and gas exploration and production company operating in Angola. Mr. Smith's additional industry experience includes leadership positions at various companies in the oil and gas industry operating in Azerbaijan, Georgia, Turkey, the United Kingdom, the United States and Canada. Mr. Smith holds a Bachelor of Commerce from the University of Calgary.

Lynne L. Hackedorn has served as Vice President, Government and Public Affairs since October 2011. Ms. Hackedorn served as our Vice President, Government, Public Affairs and Land from September 2010 until October 2011. From April 2006 until September 2010, Ms. Hackedorn served as our Vice President, Land. Ms. Hackedorn has over 29 years of experience in the oil and gas industry. Prior to joining Cobalt, from 2001 to 2006, Ms. Hackedorn served as Senior Landman at Hydro Gulf of Mexico, L.L.C., formerly Spinnaker Exploration Company, L.L.C., an oil and gas exploration and production company, handling a variety of land functions within both the shelf and deepwater areas of the Gulf of Mexico. From 1998 to 2001, Ms. Hackedorn held management positions within the offshore Gulf of Mexico regions of Sonat Exploration GOM, Inc. and El Paso Production GOM, Inc., both oil and gas exploration and production companies. From 1994 to 1998, Ms. Hackedorn was a Landman with Zilkha Energy Company, also an oil and gas exploration and production company. Ms. Hackedorn began her career as a Landman in 1984 at ARCO Oil and Gas Company, where she worked in the onshore South Texas region from 1984 until 1990, and then in the offshore Gulf of Mexico region from 1990 until 1994. Ms. Hackedorn currently also serves on the Executive Committee and Board of Directors of National Ocean Industries Association. Ms. Hackedorn earned her Bachelor of Science in Petroleum Land Management from the University of Houston, graduating Magna Cum Laude.

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Item 1A. ***Risk Factors***

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K, including the consolidated financial statements and the related notes appearing at the end of this Annual Report on Form 10-K. If any of the following risks actually occurs, our business, business prospects, stock price, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Annual Report on Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below.

Risks Relating to Our Business

Failure to effectively execute our appraisal and development projects could result in significant delays and/or cost over-runs, including the delay of any future production, which could negatively impact our operating results, liquidity and financial position.

We currently have an extensive inventory of appraisal and development projects, all of which are in the early stages of the project development life-cycle, except for our Heidelberg project. Our development projects and discoveries will require substantial additional evaluation and analysis, including appraisal drilling and the expenditure of substantial amounts of capital, prior to preparing a development plan and seeking formal project sanction. First production from these development projects and discoveries is not expected for several years, with the exception of our Heidelberg project. All of our development projects and discoveries are located in challenging deepwater environments and, given the magnitude and scale of the initial discoveries, will entail significant technical and financial challenges, including extensive subsea tiebacks to an FPSO or production platform, pressure maintenance systems, gas re-injection systems, and other specialized infrastructure. This may include the advancement of technology and equipment necessary to withstand the higher pressures associated with producing oil and gas from Inboard Lower Tertiary horizons.

This level of development activity and complexity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. In addition, we have increased dependency on third-party technology and service providers and other supply chain participants for these complex projects. We may not be able to fully execute these projects due to:

- inability to obtain sufficient and timely financing;
- inability to attract and/or retain sufficient quantity of personnel with the skills required to bring these complex projects to production on schedule and on budget;
- significant delays in delivery of essential items or performance of services, cost overruns, supplier insolvency, or other critical supply failure could adversely affect project development;
- inability to advance certain technologies;
- lack of partner or government approval for projects;
- civil disturbances, anti-development activities, legal challenges or other interruptions which could prevent access; and
- drilling hazards or accidents or natural disasters.

We may not be able to compensate for, or fully mitigate, these risks.

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Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, which may in turn limit our ability to execute our development projects and achieve production, conduct exploration activities or renew our exploration portfolio.

We do not currently generate any revenue from operations. We expect our capital outlays and operating expenditures to increase substantially over at least the next several years as we expand our operations. Developing major offshore oil and gas projects, especially in complex and challenging environments, continuing exploration activities and obtaining additional leases or concessional licenses and seismic data are very expensive, and we expect that we will need to raise substantial additional capital, through future private or public equity offerings, asset sales, strategic alliances or debt or project financing, before we generate any revenue from operations. The recent significant decline in oil and natural gas prices may make it more difficult for us to obtain additional financing.

Our future capital requirements will depend on many factors, including:

- the scope, rate of progress and cost of our project appraisal and development activities;
- the scope, rate of progress and cost of our exploration activities;
- the success of our exploration activities;
- the extent to which we invest in additional oil leases or concessional licenses;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- our ability to attract and retain adequate personnel;
- our ability to meet the timelines for development set forth in our license agreements;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the timing of partner and governmental approvals and/or concessions; and
- the effects of competition by other companies operating in the oil and gas industry.

While we believe our operations will be adequately funded at current working interests through at least 2016, we do not currently have any commitments for future external funding and we do not expect to generate any revenue from production for several years. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing stockholders could be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our leases or licenses, we would dilute our ownership interest subject to the farm-out and any potential value resulting therefrom, and we may lose operating control over such prospects.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. Assuming we are able to commence exploration and production activities or successfully exploit our properties during the primary license term, our licenses over the developed areas of a prospect could extend beyond the primary term, generally for the life of production. However, unless we make and declare discoveries within certain time periods specified in the documents governing our licenses, our interests in either the undeveloped parts of our license areas (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) may be forfeited, we may be subject to significant penalties or be required to make additional

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payments in order to maintain such licenses. The costs to maintain licenses may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. If we are not successful in raising additional capital, we may be unable to execute our development projects, continue our exploration activities or successfully exploit our properties, and we may lose the rights to develop these properties upon the expiration of our licenses.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations.

The price that we will receive for our oil and natural gas production will significantly affect our revenue, profitability, access to capital and future growth rate. The market price of oil and natural gas affects the valuation of our business and price of our common stock despite the fact that we currently do not produce or sell oil or natural gas. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil and natural gas prices depend on numerous factors. These factors include, but are not limited to, the following:

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- speculation as to the future price of oil and the speculative trading of oil futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories and oil and natural gas refining capacities;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price and availability of alternative fuels.

Significant declines in oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance our capital expenditures and results of operations;
- reducing the amount of oil and natural gas that we can produce economically;
- causing us to delay, postpone or terminate our exploration, appraisal and development activities;
- reducing any future revenues, operating income and cash flows;
- reducing the carrying value of our crude oil and natural gas properties; or

- limiting our access to sources of capital, such as equity and long-term debt.

Oil and natural gas prices have recently declined dramatically and will likely continue to be volatile in the future. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, and the market price of our common stock, results of operations, liquidity or ability to finance planned capital expenditures.

We have limited proved reserves and areas that we decide to drill may not yield hydrocarbons in commercial quantities or quality, or at all.

We have limited proved reserves and our exploration portfolio consists of identified yet unproven exploration prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. The exploration, appraisal and development wells we drill may not yield hydrocarbons in commercial quantities or quality, or at all. In addition, while our exploration efforts are oil-focused, any well we drill may discover gas or other hydrocarbons, which we may not have rights to develop or produce. Our current appraisal and development projects and exploration prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Exploration wells have been drilled on a limited number of our exploration prospects. In addition, we have drilled a limited number of appraisal wells on our discoveries. Undue reliance should not be placed on our limited drilling results or any estimates of the characteristics of our projects or prospects, including any derived calculations of our potential resources or reserves based on these limited results and estimates. Additional appraisal wells, other testing and production data from completed wells will be required to fully appraise our discoveries, to better estimate their characteristics and potential resources and reserves and to ultimately understand their commerciality and economic viability. Accordingly, we do not know how many of our development projects, discoveries or exploration prospects will contain hydrocarbons in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if hydrocarbons are found on our exploration prospects in commercial quantities, construction costs of oil pipelines, production platforms, facilities or subsea infrastructure or FPSO vessels, as applicable, and transportation costs may prevent such prospects from being economically viable development projects. We will require various regulatory approvals in order to develop and produce from any of our discoveries, which may not be forthcoming or may be delayed.

Additionally, the analogies drawn by us from available data from other wells, more fully explored prospects or producing fields may not prove valid in respect of our drilling prospects. We may terminate our drilling program for a prospect if data, information, studies and previous reports indicate that the possible development of our prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

To date, there has been limited exploration, appraisal and development drilling which has targeted the pre-salt horizon in the deepwater offshore West Africa and the Inboard Lower Tertiary trend in the deepwater U.S. Gulf of Mexico, areas in which we intend to focus a substantial amount of our exploration and development efforts.

Our discoveries and appraisal and development projects remain subject to varying degrees of additional evaluation, analysis and partner and regulatory approvals prior to official project sanction and production.

Our use of the term "development project" in this Annual Report on Form 10-K in relation to our appraisal and development activities refers to our Heidelberg, Shenandoah, North Platte, Orca and Cameia projects. Our use of the term "discoveries" in this Annual Report on Form 10-K in relation to

our exploration efforts refers to our existing discoveries: North Platte, Heidelberg, Shenandoah, Anchor, Yucatan, Cameia, Mavinga, Lontra, Bicuar, Orca and Diaman and is not intended to refer to (i) our exploration portfolio as a whole, (ii) prospects where drilling activities have not discovered hydrocarbons or (iii) our undrilled exploration prospects. A discovery made by the initial exploration well on a prospect does not ensure that we will ultimately develop or produce hydrocarbons from such prospect or that a development project will be economically viable or successful. Following a discovery by an initial exploration well, substantial additional evaluation, analysis, expenditure of capital and partner and regulatory approvals will need to be performed and obtained prior to official project sanction and development, which may include (i) the drilling of appraisal wells, (ii) the evaluation and analysis of well logs, reservoir core samples, fluid samples and the results of production tests from both exploration and appraisal wells, and (iii) the preparation of a development plan which includes economic assumptions on future oil and gas prices, the costs of drilling development wells, and the construction or leasing of offshore production facilities and transportation infrastructure. Regulatory approvals are also required to proceed with certain development plans. Relatively more testing and evaluation of our exploration, appraisal and development wells will be required for our projects and discoveries offshore West Africa than our projects in the U.S. Gulf of Mexico given the limited amount of drilling that has taken place in pre-salt horizons offshore West Africa. There is currently no oil or gas production in the pre-salt Kwanza Basin offshore Angola, an area in which we intend to devote a substantial amount of our appraisal and development activities.

Any of the foregoing steps of evaluation and analysis may render a particular development project uneconomic, and we may ultimately decide to abandon the project, despite the fact that the initial exploration well, or subsequent appraisal or development wells, discovered hydrocarbons. We may also decide to abandon a project based on forecasted oil and gas prices or the inability to obtain sufficient financing. We may not be successful in obtaining partner or regulatory approvals to develop a particular discovery, which could prevent us from proceeding with development and ultimately producing hydrocarbons from such discovery, even if we believe a development would be economically successful.

We do not currently generate any revenue from operations and our future performance is uncertain.

We do not currently generate any revenue from production and the commencement of production from our oil and gas properties will depend upon our ability to execute the appraisal and development of our projects and progress our projects through the project appraisal and development life-cycle, including the approval of development plans, obtaining formal project sanction, achieving successful appraisal and development drilling results and constructing or leasing production facilities and related subsea infrastructure. Our ability to commence production will also depend upon us being able to obtain substantial additional capital funding on a timely basis and attract and retain adequate personnel. We do not expect to commence production for at least another year, and therefore we do not expect to generate any revenue from production in the near future. Companies in their initial stages of development face substantial business and financial risks and may suffer significant losses. We have generated substantial net losses and negative cash flows from operating activities since our inception and expect to continue to incur substantial net losses as we continue our project appraisal and development activities, our exploration drilling program and our new venture activities. We face challenges and uncertainties in financial and commercial planning as a result of the complex nature of our business, the unavailability of historical data (particularly offshore West Africa) and uncertainties regarding the nature, scope and results of our future activities and financial commitments. In the event that our appraisal, development or exploration drilling schedules are not completed, or are delayed, modified or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this Annual Report on Form 10-K. As a result of industry factors or factors relating specifically to us, we may have to change our methods of conducting business, which may cause a material adverse effect on our results of operations and financial condition.

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Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing oil reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating exploration, appraisal and development wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploration wells bear a much greater risk of financial loss than development wells. In the past we have experienced unsuccessful drilling efforts. Moreover, the successful drilling of an oil well does not necessarily result in a profit on investment. A variety of factors, both geological and market-related, can cause a well or an entire development project to become uneconomic or only marginally economic. Our initial drilling sites, and any potential additional sites that may be developed, require significant additional exploration and appraisal, regulatory approval and commitments of resources prior to commercial development. We face additional risks in the Inboard Lower Tertiary Trend in the U.S. Gulf of Mexico and in the Kwanza basin offshore Angola and offshore Gabon due to a general lack of infrastructure and, in the case of offshore Angola and Gabon, underdeveloped oil and gas industries and increased transportation expenses due to geographic remoteness. Thus, this may require either a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

We contract with third parties to conduct drilling and related services on our development projects and exploration prospects for us. Such third parties may not perform the services they provide us on schedule or within budget. The recent decline in oil and gas prices may have an adverse impact on certain third parties from which we contract drilling, development and related oilfield services, which in turn could affect such companies' ability to perform such services for us and result in delays to our exploration, appraisal and development activities. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by the third parties we contract with is highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or equipment malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise, and a function of the quality of available data and the engineering and geological interpretation. Our reserves estimates are based on 12-month average prices; therefore, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. The estimates of our proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from an area compared with production from similar producing areas;

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- assumed effects of regulation by governmental agencies and court rulings;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures; and
- estimates of future severance and excise taxes, workover costs, and remedial costs.

For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, because our reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with a number of major development projects on which we are moving forward. We must successfully execute our development projects, including development drilling, in order to generate future production and cash flow. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development projects available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. Therefore, a development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. Projects in frontier areas may require the development of special technology for development drilling or well completion and we may not have the knowledge or expertise in applying new technology. All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of hydrocarbon reserves. This puts a property at higher risk for future impairment if commodity prices decrease or operating or development costs increase.

Our drilling and development plans are scheduled out over several years, making them susceptible to uncertainties that could materially alter their occurrence or timing.

Our drilling and development plans on our acreage are scheduled our over a multi-year period. Our drilling and development plans depend on a number of factors, including the availability of capital and equipment, qualified personnel, seasonal and weather conditions, regulatory and block partner approvals, civil and political conditions, oil prices, costs and drilling results. The final determination on whether to drill any exploration, appraisal, or development well, including the exact drilling location as well as the successful development of any discovery, will be dependent upon the factors described elsewhere in this Annual Report on Form 10-K as well as, to some degree, the results of our drilling activities. Because of these uncertainties, we do not know if the drilling locations we have identified or targeted will be drilled in the location we currently anticipate, within our expected timeframe or at all or if we will be able to economically produce oil or gas from these or any other potential drilling locations. As such, our actual drilling and development plans and locations may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

We are not, and may not be in the future, the operator on all of our acreage, and do not, and may not in the future, hold all of the working interests in our acreage. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and to an extent, any non-wholly owned, assets.

Currently, we are not the operator on approximately 11% of our deepwater U.S. Gulf of Mexico blocks, and we are not the operator on the Diaba Block offshore Gabon. As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future prospects that result in a greater proportion of our prospects being operated by others. In addition, the terms of our current or future licenses or leases may require at least the majority of working interests to approve certain actions. As a result, we may have limited ability to exercise influence over the operations of the prospects operated by our partners or which are not wholly-owned by us, as the case may be. Dependence on the operator or our partners could prevent us from realizing our target returns for those prospects. Further, it may be difficult for us to minimize the cycle time between discovery and initial production with respect to prospects for which we do not operate or wholly-own. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- partner, government and regulatory approvals;
- selection of technology; and
- the rate of production of reserves, if any.

Furthermore, even though we are the operator of Blocks 9, 20 and 21 offshore Angola, we are required to obtain the prior approval of Sonangol for most of our operational activities. This limited ability to exercise control over the operations of some of our prospects may cause a material adverse effect on our results of operations and financial condition.

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or lease partners. As a result of our exploration success, we have a large inventory of development projects which will require significant capital expenditures and have long development cycle times. Our partners, both in the U.S. Gulf of Mexico and West Africa, must be able to fund their share of investment costs through the lengthy development cycle, through cash flow from operations, external credit facilities, or other sources, including project financing arrangements. Our partners may not be successful in obtaining such financing, which could negatively impact the progress and timeline for development. In addition to project development costs, our partners must also be able to fund their share of exploration and other operating expenses. If any of our partners in the blocks or leases in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In response to the recent decline in oil and gas prices, certain of our partners have announced capital expenditure reductions, which may cause such partners to elect not to participate in the drilling of a particular exploration or appraisal well with us. This could increase our share of the costs of such operation and may cause us to cancel or delay certain exploration or appraisal drilling programs.

In addition, if any of the service providers we contract with to conduct development or exploration activities file for bankruptcy or are otherwise unable to fulfill their obligations to us, we may face increased costs and delays in locating replacement vendors. The recent decline in oil and gas prices may have an adverse impact on certain third parties from which we contract drilling, development and

related oilfield services, which in turn could affect such companies' ability to perform such services for us and result in delays to our exploration, appraisal and development activities. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our business, results of operations or financial condition.

We are dependent on certain members of our management and technical team and our inability to retain or recruit qualified personnel may impair our ability to grow our business.

Our investors must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, discovering and developing oil reserves and progressing our development projects toward first production. Our performance and success are dependent, in part, upon key members of our management and technical team, and their loss or departure could be detrimental to our future success. You must be willing to rely to a significant extent on our management's discretion and judgment. In addition, a significant portion of our employee base is at or near retirement age. Furthermore, we utilize the services of a number of individual consultants for contractually fixed periods of time. Our inability to retain or recruit qualified personnel may impair our ability to grow our business and develop our discoveries, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

Under the terms of our various license agreements, we are required to drill wells, declare any discoveries and conduct certain development activities in order to retain exploration and production rights and failure to do so may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various license agreements and leases, our interests in the undeveloped parts of our license (as is the case in Angola and Gabon) or the whole block (as is the case in the deepwater U.S. Gulf of Mexico) areas may lapse and we may be subject to significant penalties or be required to make additional payments in order to maintain such licenses. For example, pursuant to the terms of the Block 21 RSA, the initial exploration period with respect to Block 21 offshore Angola will terminate on March 1, 2015 and, on such date we will lose our exploration rights on Block 21. We have applied for an extension of the initial exploration period for Block 21 to enable us to continue our exploration efforts, however, this extension is currently pending approval by Sonangol and the Angola Ministry of Petroleum. We can make no assurances that we will receive an extension of the initial exploration period on Block 21 or what the terms of the extension might be. Under the Block 20 PSC, in order to preserve our rights in the block, we will be required to drill four exploration wells within five years of the signing of the Block 20 PSC, or January 1, 2017, subject to certain extensions. Currently, we have drilled two exploration wells on Block 20.

Furthermore, as required by our license agreements, within thirty days following a successful exploration well, we are required to submit a declaration of commercial well to Sonangol. Within two years after the date of the declaration of commercial well, we must submit to Sonangol a formal declaration of commercial discovery. Within three months from the declaration of commercial discovery, we are required to submit a development plan to Sonangol and the Angola Ministry of Petroleum for review and approval. Within forty-two months after the formal declaration of commercial discovery, we are required to commence first production from such discovery. Given our exploration success, we now have five complex appraisal and development projects offshore Angola, including Cameia, Mavinga, Lontra, Orca and Bicuar, each of which we must progress through the project development life-cycle in order to comply with the deadlines outlined above. Our failure or inability to meet these deadlines could jeopardize our production rights or result in forfeiture of our production

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rights with respect to these projects, which would have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

In addition, most of our deepwater U.S. Gulf of Mexico blocks have a 10-year primary term, expiring between 2016 and 2024. Generally, we are required to commence exploration activities or successfully exploit our properties during the primary lease term in order for these leases to extend beyond the primary lease term. A portion of the leases covering our Shenandoah and Anchor discoveries are beyond their primary term, and the operator must conduct continuous operations or obtain a Suspension of Production in order to maintain such leases. Accordingly, we and our partners may not be able to drill all of the prospects identified on our leases or licenses prior to the expiration of their respective terms and we can make no assurances that the operator of the discoveries in which we hold a non-operated interest will be able to successfully perpetuate leases through continuous operations or obtaining a Suspension of Production. Should the prospects we have identified under the licenses or leases currently in place yield discoveries, we cannot assure you that we will not face delays in drilling these prospects or otherwise have to relinquish these prospects. The costs to maintain licenses over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business. For each of our blocks and license areas, we cannot assure you that any renewals or extensions will be granted or whether any new agreements or leases will be available on commercially reasonable terms, or, in some cases, at all.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental, safety, health and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental, safety, and health liabilities and could acquire assets on an "as is" basis. Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

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The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploration prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of environmental, safety and health or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve many risks that a combination of experience, knowledge and careful evaluation may not be able to overcome. Our future success will depend on the success of our exploration and production activities and on the future existence of the infrastructure and technology that will allow us to take advantage of our findings. Additionally, our properties are located in deepwater, which generally increases the capital and operating costs, technical challenges and risks associated with exploration and production activities. As a result, our exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected production from our prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of oil and gas prices, proximity, capacity and availability of pipelines, the availability of processing facilities, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of hydrocarbons, environmental, safety, health and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

We are subject to drilling and other operational hazards.

The exploration and production business involves a variety of operating risks, including, but not limited to:

- blowouts, cratering and explosions;
- mechanical and equipment problems;
- uncontrolled flows or leaks of oil or well fluids, natural gas or other pollution;
- fires and gas flaring operations;
- marine hazards with respect to offshore operations;

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- formations with abnormal pressures;
- pollution, other environmental risks and geological problems; and
- weather conditions and natural disasters.

These risks are particularly acute in deepwater drilling and exploration for natural resources. Any of these events could result in loss of human life, significant damage to property, environmental damage, impairment of our operations, delays in our drilling operations, increased costs and substantial losses. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

We are members of several industry groups that provide general and specific oil spill and well containment resources in the U.S. Gulf of Mexico and offshore West Africa. Through these industry groups, as described under "Business—Containment Resources", we have contractual rights to access certain oil spill and well containment resources. We can make no assurance that these resources will perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons. Furthermore, our contracts for the use of oil spill and well containment resources contain strict indemnity provisions that generally require us to indemnify the contractor for all losses incurred as a result of assisting us in our oil spill and well containment efforts, subject to certain exceptions and limitations. In the event we experience a subsea blowout, explosion, fire, uncontrolled flow of hydrocarbons or any of the other operational risks identified above, the oil spill and well containment resources which we have contractual rights to will not prevent us from incurring losses or shield us from liability, which could be substantial and have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

The high cost or unavailability of drilling rigs, equipment, transportation, personnel, oil field services and infrastructure could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, transportation, supplies or qualified personnel, often during periods of higher oil prices or in emerging areas of exploration. During these periods and within these areas, the costs of drilling rigs, equipment, transportation, supplies and personnel are substantially greater and their availability may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, transportation, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our ability to produce hydrocarbons will depend substantially on the availability and capacity of gathering systems, pipelines, processing facilities and tanker transportation owned and operated by third parties. Additionally, such infrastructure may not be available on commercially reasonable terms. We may be required to shut in oil wells because of the absence of a market or because access to pipelines, gathering systems, processing facilities or tanker transportation may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could have a material adverse effect on our business, financial condition or results of operations.

Our operations will involve special risks that could adversely affect operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions.

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These conditions can cause substantial damage to facilities and interrupt our operations. As a result, we could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Deepwater exploration generally involves greater operational and financial risks than exploration on the shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. Such risks are particularly applicable to our deepwater exploration efforts in the Inboard Lower Tertiary trend and pre-salt offshore Angola and Gabon. In addition, there may be production risks of which we are currently unaware. Whether we use existing pipeline infrastructure, participate in the development of new subsea infrastructure or use floating production systems to transport oil from producing wells, if any, these operations may require substantial time for installation, or encounter mechanical difficulties and equipment failures that could result in significant cost overruns and delays. Furthermore, deepwater operations generally, and operations in the Inboard Lower Tertiary and offshore West Africa trends in particular, lack the physical and oilfield service infrastructure present on the shelf. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated hydrocarbons, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of this infrastructure, oil and gas discoveries we make in the deepwater, if any, may never be economically producible.

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

Our operations in the U.S. Gulf of Mexico may be adversely impacted by tropical storms and hurricanes.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations in the U.S. Gulf of Mexico as well as operations within the path and the projected path of the tropical storms or hurricanes. In the future, during a shutdown period, we may be unable to access wellsites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to offshore drilling rigs and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which may have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

The geographic concentration of our properties in the U.S. Gulf of Mexico and offshore Angola and Gabon subjects us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting the U.S. Gulf of Mexico and offshore Angola and Gabon.

Our properties are concentrated in three countries: the U.S. Gulf of Mexico and offshore Angola and Gabon. Some or all of these properties could be affected should such regions experience:

- severe weather or natural disasters;
- moratoria on drilling or permitting delays;
- delays in or the inability to obtain regulatory approvals;
- delays or decreases in production;
- delays or decreases in the availability of drilling rigs and related equipment, facilities, personnel or services;

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- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- changes in the regulatory, political and fiscal environment.

For example, in response to the Deepwater Horizon incident in 2010, the U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI and the BOEM and the BSEE, imposed moratoria on drilling operations, required operators to reapply for exploration plans and drilling permits and adopted extensive new regulations, which effectively had halted drilling operations in the deepwater U.S. Gulf of Mexico for a period of time. Additionally, oil and gas properties and facilities located in the U.S. Gulf of Mexico were significantly damaged by Hurricanes Katrina and Rita in 2005, which required our competitors to spend a significant amount of time and capital on inspections, repairs, debris removal, and the drilling of replacement wells. We maintain insurance coverage for only a portion of these risks. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss. We do not carry business interruption insurance.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

Regulations enacted as a result of the Deepwater Horizon drilling rig accident and resulting oil spill may have significantly increased certain of the risks we face and increased the cost of operations in the U.S. Gulf of Mexico.

On April 20, 2010, the Transocean Deepwater Horizon, a semi-submersible offshore drilling rig operating in the deepwater U.S. Gulf of Mexico under contract to BP plc exploded, burned for two days and sank, resulting in loss of life, injuries and a large oil spill. The U.S. government and its regulatory agencies with jurisdiction over oil and gas exploration, including the DOI, the BOEM and the BSEE, responded to this incident by imposing moratoria on drilling operations and adopting numerous new regulations and new interpretations of existing regulations regarding operations in the U.S. Gulf of Mexico. Compliance with these new regulations and interpretations has increased the cost of our drilling operations in the U.S. Gulf of Mexico.

The successful execution of our U.S. Gulf of Mexico business plan depends on our ability to continue our exploration and appraisal efforts. A prolonged suspension of or delay in our drilling operations would adversely affect our business, financial position or future results of operations.

Furthermore, the Deepwater Horizon incident has increased and may further increase certain of the risks we face, including, without limitation, the following:

- increased governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and inspections and training requirements;
- increased difficulty in obtaining leases and permits to drill offshore wells, including as a result of any bans or moratoria placed on offshore drilling;
- potential legal challenges to the issuance of permits and the conducting of our operations;
- higher drilling and operating costs;
- higher royalty rates and fees on leases acquired in the future;
- higher insurance costs and increased potential liability thresholds under proposed legislation and regulations;

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- decreased partner participation in wells we operate;
- higher capital costs as a result of any increase to the risks we or our industry face; and
- less favorable investor perception of the risk-adjusted benefits of deepwater offshore drilling.

The occurrence of any of these factors, or their continuation, could have a material adverse effect on our business, financial position or future results of operations.

We face various risks associated with increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations such as offshore drilling and development. For example, environmental activists have recently challenged lease sales and decisions to grant air-quality permits in the U.S. Gulf of Mexico for offshore drilling.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering, processing or production facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased regulation;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act, and any determination that we violated the U.S. Foreign Corrupt Practices Act could have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove

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to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

In connection with entering into our RSAs for Blocks 9 and 21 offshore Angola, two Angolan-based E&P companies were assigned as part of the contractor group by the Angolan government. We had not worked with either of these companies in the past, and, therefore, our familiarity with these companies was limited. In the fall of 2010, we were made aware of allegations of a connection between senior Angolan government officials and one of these companies, Nazaki Oil and Gáz, S.A. ("Nazaki"), which was a full paying member of the contractor group but is no longer a member of such group. In March 2011, the SEC commenced an informal inquiry into these allegations. To avoid non-overlapping information requests, we voluntarily contacted the U.S. Department of Justice ("DOJ") with respect to the SEC's informal request and offered to respond to any requests the DOJ may have. Since such time, we have complied with all requests from the SEC and DOJ with respect to their inquiry. In November 2011, a formal order of investigation was issued by the SEC related to our operations in Angola. In August 2014, we received a Wells Notice from the SEC related to this investigation. In January 2015, we received a termination letter from the SEC advising us that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. We continue to cooperate with the DOJ with regard to its ongoing parallel investigation. We have conducted an extensive investigation into these allegations and believe that our activities in Angola have complied with all laws, including the FCPA. We are unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue, or otherwise provide any assurance regarding the duration, scope, developments in, results of or consequences of its investigation.

In the future, we may be partnered with other companies with whom we are unfamiliar. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the government may seek to hold us liable for successor liability FCPA violations committed by companies in which we invest or that we acquire.

A change in U.S. energy policy could have a significant impact on our operations and profitability.

U.S. energy policy and laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential rules and regulations that could impact the sources and uses of energy in the United States. For example, new CAFE standards enacted in 2012 will result in a significant increase in the fuel economy of cars and light trucks and will reduce the future demand for crude oil for road transport use. GHG emissions regulations may increase the demand for natural gas as fuel for power generation.

We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are impacted in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in U.S. energy policy.

Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business.

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We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business. See "Legal Proceedings." We are vigorously defending against the current lawsuits and do not believe it will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

Because we maintain a diversified portfolio of assets that includes both U.S. and international projects, the complexity and types of legal proceedings with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our oil and gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Angola and Gabon.

Our operations are exposed to risks of war, local economic conditions, political disruption, civil disturbance and governmental policies that may:

- disrupt our operations;
- restrict the movement of funds or limit repatriation of profits;
- in the case of our non-U.S. operations, lead to U.S. government or international sanctions; and
- limit access to markets for periods of time.

Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our financial condition and results of operations. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the U.S. or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the U.S., which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Angola, Gabon, the United States, the Cayman Islands and other jurisdictions, in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof, could have a material adverse effect on our results of operations and financial position, as well as on the market price of our common stock.

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Outbreaks of disease in the geographies in which we operate may adversely affect our business operations and financial condition.

Many of our operations are currently, and will likely remain in the near future, in developing countries which are susceptible to outbreaks of disease and may lack the resources to effectively contain such an outbreak quickly. Such outbreaks may impact our ability to explore for oil and gas, develop or produce our license areas by limiting access to qualified personnel, increasing costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and oil and gas production to and from our areas of operation and diverting the time, attention and resources of government agencies which are necessary to conduct our operations. In addition, any losses we experience as a result of such outbreaks of disease which impact sales or delay production may not be covered by our insurance policies.

An epidemic of the Ebola virus disease is currently ongoing in parts of West Africa. A substantial number of deaths have been reported by the World Health Organization ("WHO") in West Africa, and the WHO has declared it a global health emergency. It is impossible to predict the effect and potential spread of the Ebola virus in West Africa and surrounding areas. Should the Ebola virus continue to spread, including to the countries in which we operate, or not be satisfactorily contained, our exploration, development and production plans for our operations could be delayed, or interrupted after commencement. Any changes to these operations could significantly increase costs of operations. Our operations require contractors and personnel to travel to and from Africa as well as the unhindered transportation of equipment and oil and gas production (in the case of our producing fields). Such operations also rely on infrastructure, contractors and personnel in Africa. If travel bans are implemented or extended to the countries in which we operate, including Angola or Gabon, or contractors or personnel refuse to travel there, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow.

The oil and gas industry, including the acquisition of exploration acreage worldwide, is intensely competitive.

The international oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of oil and gas. We operate in a highly competitive environment for acquiring exploration acreage and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be able to pay more for productive or prospective properties and prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drill attempts, delays, sustained periods of volatility in financial markets and generally adverse global and industry- wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. Our ability to acquire additional exploration prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

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Participants in the oil and gas industry are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to extensive local, state, federal and international regulations. We may be required to make large expenditures to comply with governmental regulations, particularly in respect of the following matters:

- licenses and leases for drilling operations;
- foreign exchange and banking;
- royalty increases, including retroactive claims;
- drilling and development bonds and social payment obligations;
- reports concerning operations;
- the spacing of wells;
- unitization of oil accumulations;
- environmental remediation or investigation; and
- taxation.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages for which we may not maintain, or otherwise be protected by, insurance coverage. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

For example, Angola has enacted a new Foreign Exchange Law for the Petroleum Sector, which requires, among other things, that all foreign exchange operations be carried out through Angolan banks, that oil and gas exploration and production companies open local bank accounts in foreign currencies in order to pay local taxes and to pay for goods and services supplied by non-resident suppliers and service providers, and also that oil and gas exploration and production companies open local bank accounts in local currency in order to pay for goods and services supplied by resident suppliers and service providers. See "Business—Laws and Regulations of Angola and Gabon—Angola" for more information. These new rules require additional compliance efforts and costs on our and other industry participants' part, and may in some cases cause delay or other issues in connection with the acquisition of or payments for goods and services. Any of these consequences could have a material adverse effect on our results of operations.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including

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vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas in increasingly difficult physical environments, such as below-salt deepwater, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. For example, in 2012, a wave of network attacks impacted Saudi Arabia's oil industry and breached financial institutions in the US. Certain countries, including China, Russia and Iran, are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

We and our operations are subject to numerous environmental, health and safety regulations which may result in material liabilities and costs.

We are, and our future operations will be, subject to various international, foreign, federal, state and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use and transportation of regulated materials and the health and safety of our employees. We are required to obtain various environmental permits from governmental authorities for our operations, including drilling permits for our wells. There is a risk that we have not been or will not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject. If we violate or fail to comply with these laws, regulations or permits, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain permits in a timely manner or at all (due to opposition from community or environmental interest groups, governmental delays, changes in laws or the interpretation thereof or any other reasons), such failure could impede our operations, which could have a material adverse effect on our results of operations and our financial condition.

We, as the named lessee or as the designated operator under our current and future oil leases and licenses, could be held liable for all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our third-party contractors. To the extent we do not address these costs and liabilities or if we are otherwise in breach of our lease or license requirements, our leases or licenses could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform the majority of the drilling and other services related to our operations. There is a risk that we may contract with third parties with unsatisfactory environmental, health and safety records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of the acts or omissions of our contractors, which could have a material adverse effect on our results of operations and financial condition.

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As the designated operator of certain of our leases and licenses, we are required to maintain bonding or insurance coverage for certain risks relating to our operations, including environmental risks. We maintain insurance at levels that we believe are consistent with current industry practices, but we are not fully insured against all risks. Our insurance may not cover any or all environmental claims that might arise from our operations or those of our third-party contractors. If a significant accident or other event occurs and is not fully covered by our insurance, or our third-party contractors have not agreed to bear responsibility, such accident or event could have a material adverse effect on our results of operations and our financial condition. In addition, we may not be able to obtain required bonding or insurance coverage at all or in time to meet our anticipated startup schedule for each well, and if we fail to obtain this bonding or coverage, such failure could have a material adverse effect on our results of operations and financial condition.

Releases to deepwater of regulated substances are common, and under certain environmental laws, we could be held responsible for all of the costs relating to any contamination caused by us or our contractors, at our facilities and at any third party waste disposal sites used by us or on our behalf. These costs could be material. In addition, offshore oil exploration and production involves various hazards, including human exposure to regulated substances, including naturally occurring radioactive materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or other damage resulting from the release of regulated substances to the environment, endangered species, property or to natural resources.

Particularly since the Deepwater Horizon event in the U.S. Gulf of Mexico in 2010, there has been an increased interest in making regulation of deepwater oil and gas exploration and production more stringent in the U.S. If adopted, certain proposals such as a significant increase or elimination of financial liability caps for economic damages, could significantly raise daily penalties for infractions and require significantly more comprehensive financial assurance requirements under OPA which could affect our results of operations and our financial condition.

In addition, we expect continued attention to climate change issues. Various countries and U.S. states and regions have agreed to regulate emissions of greenhouse gases ("GHG"), including methane (a primary component of natural gas) and carbon dioxide, a byproduct of oil and natural gas combustion. Additionally, the U.S. Congress has in the past and may in the future consider legislation requiring reductions in GHG emissions. The EPA began regulating GHG emissions from certain stationary sources in January 2011 and has enacted GHG emissions standards for certain classes of vehicles. The EPA has adopted rules requiring the reporting of GHG emissions, including from certain offshore oil and natural gas production facilities on an annual basis. In addition, in accordance with the Obama Administration's June 2013 Climate Action Plan ("CAP"), the EPA published proposed rules in January 2014 and June 2014 to regulate GHG emissions from new power plants and GHG emissions applicable to existing power plants, respectively. EPA announced it will finalize these proposals by summer 2015. The CAP also calls upon EPA and other governmental agencies to identify ways in which to reduce methane emissions from various sectors, including the oil and gas industry. On January 14, 2015, the White House unveiled these plans which, among other things directs the EPA to propose rules to regulate methane emissions from the oil and gas industry from new and modified sources by summer 2015, with a finalized rule in 2016. The EPA is also directed to expand the GHG Reporting Rule to cover all segments of the oil and gas industry. The regulation of GHGs and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future environmental, health and safety laws, and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and our financial condition. See "Business—Environmental Matters and Regulation."

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Non-U.S. holders of our common stock, in certain situations, could be subject to U.S. federal income tax upon the sale, exchange or other disposition of our common stock.

Our assets consist primarily of interests in U.S. oil and gas properties (which constitute U.S. real property interests for purposes of determining whether we are a U.S. real property holding corporation) and interests in non-U.S. oil and gas properties, the relative values of which at any time may be uncertain and may fluctuate significantly over time. Therefore, we may be, now or at any time while a non-U.S. investor owns our common stock, a U.S. real property holding corporation. As a result, under the Foreign Investment in Real Property Tax Act ("FIRPTA"), certain non-U.S. investors may be subject to U.S. federal income tax on gain from the disposition of shares of our common stock, in which case they would also be required to file U.S. tax returns with respect to such gain. Whether these FIRPTA provisions apply depends on the amount of our common stock that such non-U.S. investors hold and whether, at the time they dispose of their shares, our common stock is regularly traded on an established securities market (such as the New York Stock Exchange ("NYSE")) within the meaning of the applicable Treasury Regulations. So long as our common stock is listed on the NYSE, only a non-U.S. investor who has held, actually or constructively, more than 5% of our common stock may be subject to U.S. federal income tax on the disposition of our common stock under FIRPTA.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

Several external factors could arise which would significantly impact our ability to effectively insure our oil and natural gas exploration and development operations. Should legislation be passed to increase the minimum insurance limit of the OSFR policy required for future U.S. Gulf of Mexico oil and natural gas exploration, there is no assurance that we will be able to obtain this insurance. The insurance markets may not provide products to financially insure us against all operational risks. For instance, civil and criminal penalties for environmental pollution can be very severe and may not be insurable. For some risks, we may not obtain insurance if we believe the market price of available insurance is excessive or prohibitive relative to the risks presented. For instance, we do not purchase business interruption or wind insurance due to the market pricing.

Even when insurance is purchased, exclusions in coverage, unanticipated circumstances and potentially large indemnity obligations may have a material adverse effect on our operations and financial condition. Because third-party contractors and other service providers are used in our offshore operations, we may not realize the intended protections of worker's compensation laws in dealing with their employees. Generally, under our contracts with drilling and other oilfield service contractors, we are obligated, subject to certain exceptions and limitations, to indemnify such contractors for all claims arising out of damage to our property, injury or death to our employees and pollution emanating from the well-bore, including pollution resulting from blow-outs and uncontrolled flows of hydrocarbons.

Our level of indebtedness may increase and thereby reduce our financial flexibility.

We have issued $2.68 billion aggregate principal amount of convertible senior notes (the "notes"). The notes do not contain restrictive covenants, and we may incur significant additional indebtedness in the future in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets. Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows, if and when generated, could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;

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- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing; and

- a high level of indebtedness may impair our ability to obtain additional financing in the future for our development projects, exploration drilling program, working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital.

The conditional conversion feature of our 3.125% senior convertibles notes due 2024, if triggered, may adversely affect our financial condition and operating results.

If the conditional conversion feature of our 3.125% senior convertibles notes due 2024 is triggered, holders of such notes will be entitled to convert these notes at any time during specified periods outlined in the indenture governing such notes, at their option. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of these notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

Conversions of the notes may adversely affect our financial condition and operating results.

Holders of notes will be entitled to convert the notes at their option at any time up until the maturity date, being December 1, 2019 for the 2.625% convertible senior notes due 2019 and May 15, 2024 for the 3.125% senior convertible notes due 2024. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely shares of our common stock (other than cash in lieu of any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of the notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

The accounting method for convertible debt securities that may be settled in cash, such as the notes, could have a material effect on our reported financial results.

Under Accounting Standards Codification 470-20, Debt with Conversion and Other Options, which we refer to as ASC 470-20, an entity must separately account for the liability and equity components of the convertible debt instruments (such as the notes) that may be settled entirely or partially in cash upon conversion in a manner that reflects the issuer's economic interest cost. The effect of ASC 470-20 on the accounting for the notes is that the equity component is required to be included in the

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additional paid-in capital section of stockholders' equity on our consolidated balance sheet, and the value of the equity component would be treated as original issue discount for purposes of accounting for the debt component of the notes. As a result, we will be required to record a greater amount of non-cash interest expense in current periods presented as a result of the amortization of the discounted carrying value of the notes to their face amount over the term of the notes. We will report lower net income in our financial results because ASC 470-20 will require interest to include both the current period's amortization of the debt discount and the instrument's coupon interest, which could adversely affect our reported or future financial results, the trading price of our common stock and the trading price of the notes.

We may account for the notes utilizing the treasury stock method. The effect of this method is that the shares issuable upon conversion of convertible securities are not included in the calculation of diluted earnings per share except to the extent that the conversion value of such securities exceeds their principal amount. Under the treasury stock method, for diluted earnings per share purposes, the notes would be accounted for as if the number of shares of common stock that would be necessary to settle such excess, if we elected to settle such excess in shares, are issued.

However, we cannot be sure that the accounting standards in the future will continue to permit the use of the treasury stock method. If we are unable to use the treasury stock method in accounting for the shares issuable upon conversion of the notes, for whatever reason, then we would have to apply the if-converted method, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings per share if the effect would be antidilutive. Under the if-converted method, for diluted earnings per share purposes, convertible debt is antidilutive whenever its interest, net of tax and nondiscretionary adjustments, per common share obtainable on conversion exceeds basic earnings per share. Dilutive securities that are issued during a period and dilutive convertible securities for which conversion options lapse, or for which related debt is extinguished during a period, will be included in the denominator of diluted earnings per share for the period that they were outstanding. Likewise, dilutive convertible securities converted during a period will be included in the denominator for the period prior to actual conversion. Moreover, interest charges applicable to the convertible debt will be added back to the numerator.

Risks Relating to our Common Stock

Our stock price may be volatile, and investors in our common stock could incur substantial losses.

Our stock price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common stock may be influenced by many factors, including, but not limited to:

- to what extent our exploration wells are successful;
- the price of oil and natural gas;
- the success of our development operations, and the marketing of any oil and gas we produce;
- regulatory developments in the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- increases in operating costs, including cost overruns associated with our exploration and development activities;

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- analysts' reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- the issuance or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete and areas in which we operate; and
- general economic, political and market conditions.

A substantial portion of our total outstanding shares may be sold into the market at any time. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares sold in our public offerings are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all the remaining shares of common stock are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rules 144 or 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates, and other limitations under Rule 144. Additionally, we have registered all shares of our common stock that we may issue under our employee and director benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these stock awards have transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

Conversion of the notes may dilute the ownership interest of existing stockholders, including holders who have previously converted their notes.

The conversion of some or all of the notes may dilute the ownership interests of existing stockholders. Any sales in the public market of any shares of our common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the anticipated conversion of the notes into shares of our common stock or a combination of cash and shares of our common stock could depress the price of our common stock.

Holders of our common shares will be diluted if additional shares are issued.

We may issue additional shares of common stock, preferred stock, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We may issue additional shares of common stock in connection with complementary or strategic acquisitions of assets or businesses. We also issue restricted stock to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Ownership of our capital stock is concentrated among our largest stockholders and their affiliates.

A small number of stockholders hold a majority of our common stock. These stockholders have influence over all matters that require approval by our stockholders, including the election of directors

and approval of significant corporate transactions. This concentration of ownership may limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial. Furthermore, these stockholders may sell their shares of common stock at any time. Such sales could be substantial and adversely affect the market price of our common stock.

Provisions of our certificate of incorporation and by-laws could discourage potential acquisition proposals and could deter or prevent a change in control.

Some provisions in our certificate of incorporation and by-laws, as well as Delaware statutes, may have the effect of delaying, deferring or preventing a change in control. These provisions, including those providing for the possible issuance of shares of our preferred stock and the right of the board of directors to amend the by-laws, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire a substantial number of shares of our common stock or to launch other takeover attempts that a stockholder might consider to be in his or her best interest. These provisions could limit the price that some investors might be willing to pay in the future for shares of our common stock.

Provisions of the notes could discourage an acquisition of us by a third party.

Certain provisions of the notes could make it more difficult or more expensive for a third party to acquire us, or may even prevent a third party from acquiring us. For example, upon the occurrence of a fundamental change, holders of the notes will have the right, at their option, to require us to repurchase all of their notes or any portion of the principal amount of such notes in integral multiples of $1,000. In addition, the acquisition of us by a third party could require us, under certain circumstances, to increase the conversion rate for a holder who elects to convert its notes in connection with such acquisition. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common stock of an opportunity to sell their common stock at a premium over prevailing market prices.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Consequently, investors must rely on sales of their shares of common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. ***Unresolved Staff Comments***

Not applicable.

Item 2. ***Properties***

Please refer to the information under the caption "Business" in this Annual Report on Form 10-K.

Item 3. ***Legal Proceedings***

We are currently, and from time to time we may become, involved in various legal and regulatory proceedings arising in the normal course of business.

On November 30, 2014, two purported stockholders, St. Lucie County Fire District Firefighters' Pension Trust Fund and Fire and Police Retiree Health Care Fund, San Antonio, filed a class action lawsuit in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through November 4, 2014 (the "*St. Lucie* lawsuit"). The *St. Lucie* lawsuit, filed against us and certain officers, former and current members of

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the Board of Directors, underwriters, and investment firms and funds, asserts violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures, primarily regarding compliance with the U.S. Foreign Corrupt Practices Act ("FCPA") in our Angolan operations and the performance of certain wells offshore Angola. On December 4, 2014, Steven Neuman, a purported stockholder, filed a substantially similar lawsuit against us and certain of our officers in the U.S. District Court for the Southern District of Texas on behalf of a putative class of all purchasers of our securities from February 21, 2012 through August 4, 2014 (the "*Neuman* lawsuit"). Like the *St. Lucie* lawsuit, the *Neuman* lawsuit asserts violations of federal securities laws based on alleged misrepresentations and omissions in SEC filings and other public disclosures regarding our compliance with the FCPA in our Angolan operations. Among other remedies, both the *St. Lucie* and *Neuman* lawsuits seek damages in an unspecified amount, along with an award of attorney fees and other costs and expenses to the plaintiffs. Motions to consolidate the two actions are currently pending. The deadline to apply for appointment as lead plaintiff was February 2, 2015. The Court has set a scheduling conference on March 2, 2015 to consider all pending motions.

On January 16, 2015, Edward Ogden, a purported stockholder, filed a derivative action in the U.S. District Court for the Southern District of Texas against us, as a nominal defendant, and certain of our officers and former and current directors. The lawsuit alleges that the individual defendants breached their fiduciary duties, including in relation to compliance with the FCPA in our Angolan operations and regarding the performance of certain wells offshore Angola. The lawsuit further alleges that certain officers received performance-based compensation in excess of what they were entitled and that certain officers and directors engaged in unlawful trading. The lawsuit also alleges that the plaintiff was excused from making a demand on the basis of futility. The plaintiff asserts claims for breach of fiduciary duty, unjust enrichment, and corporate waste. The plaintiff seeks damages in an unspecified amount, disgorgement of profits, appropriate equitable relief, and an award of attorney fees and other costs and expenses. Based upon an agreement with the plaintiff, we are required to plead, answer, or otherwise respond to the lawsuit in March 2015.

We are vigorously defending against the current lawsuits and do not believe they will have a material adverse effect on our business. However, we cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these litigations and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations. For more information, see "Risk Factors—Risks Related to Our Business—We operate in a litigious environment."

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock is traded on the NYSE under the symbol "CIE." On January 30, 2015, the last reported sale price for our common stock on NYSE was $9.12 per share. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NYSE.

	High	Low
Year ending December 31, 2015		
First Quarter (through January 30, 2015)	$ 9.28	$ 7.77
Year ended December 31, 2014		
Fourth Quarter	$ 13.76	$ 7.40
Third Quarter	18.42	13.38
Second Quarter	19.77	16.90
First Quarter	19.90	15.36
Year ended December 31, 2013		
Fourth Quarter	$ 25.31	$ 13.75
Third Quarter	30.27	24.15
Second Quarter	29.34	24.65
First Quarter	28.56	22.25

Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that we specifically incorporate it by reference into such filing.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of our common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on our common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from

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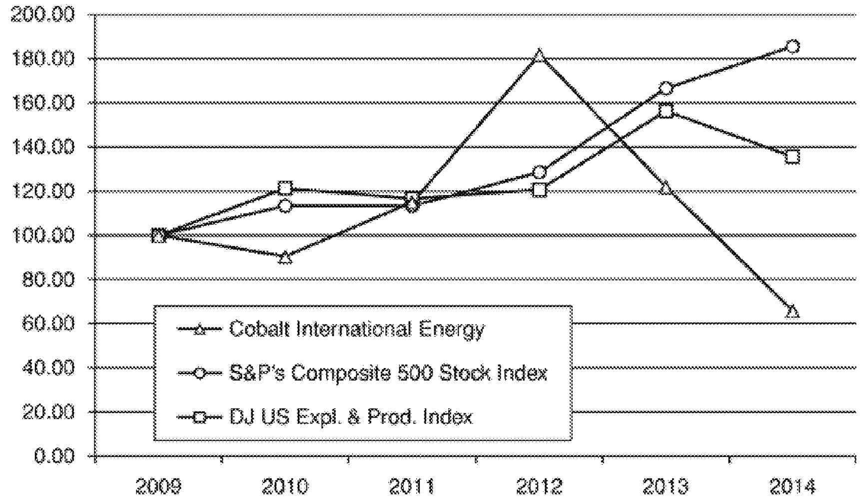
December 16, 2009, the date we commenced trading on the New York Stock Exchange, through December 31, 2014.



An investment of $100 is assumed to have been made in our common stock, in the S&P's Composite 500 Stock Index (with reinvestment of all dividends) and in the Dow Jones U.S. Exploration & Production Index on December 16, 2009, and its relative performance is tracked through December 31, 2014:

	As of December 16, 2009	Year Ended December 31, 2010	2011	2012	2013	2014
Cobalt International Energy, Inc.	$ 100.00	$ 90.44	$ 114.96	$ 181.93	$ 121.85	$ 65.85
S&P's Composite 500 Stock Index	100.00	113.38	113.38	128.58	166.64	185.62
Dow Jones U.S. Exploration & Production Index	100.00	121.27	116.66	120.68	156.35	135.67

Holders

As of December 31, 2014, there were approximately 192 holders of record of our common stock. The number of record holders does not include holders of shares in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

Dividend Policy

At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. The decision to pay dividends on our common stock is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant.

Equity Compensation Plan

For information on securities authorized under our equity compensation plans, see the section entitled "Executive Compensation—Equity Compensation Plan Information" in our definitive Proxy Statement for our annual meeting of stockholders to be held on April 30, 2015.

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Item 6. ***Selected Financial Data***

The selected historical financial information set forth below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with our financial statements and the notes to those financial statements included elsewhere in this Annual Report on Form 10-K. The consolidated statements of operations and cash flows information for the years ended December 31, 2014, 2013, 2012, 2011, and 2010 were derived from Cobalt International Energy, Inc.'s audited financial statements.

Consolidated Statement of Operations Information:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	($ in thousands except per share data)				
Oil and gas revenue	$ —	$ —	$ —	$ —	$ —
Operating costs and expenses					
Seismic and exploration	85,567	74,213	61,583	32,239	45,030
Dry hole expense and impairment	236,930	351,050	134,085	45,732	44,178
General and administrative	114,860	105,547	87,963	59,130	48,063
Depreciation and amortization	4,584	1,874	1,197	735	787
Total operating costs and expenses	441,941	532,684	284,828	137,836	138,058
Operating income (loss)	(441,941)	(532,684)	(284,828)	(137,836)	(138,058)
Other income (expense):					
Gain (loss) on sale of assets	(12)	2,993	—	—	—
Interest income	5,958	6,043	5,041	4,199	1,582
Interest expense	(74,768)	(65,376)	(3,212)	—	—
Total other income (expense)	(68,822)	(56,340)	1,829	4,199	1,582
Net income (loss) before income tax	(510,763)	(589,024)	(282,999)	(133,637)	(136,476)
Income tax expense (benefit)(1)	—	—	—	—	—
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)	$ (133,637)	$ (136,476)
Basic and diluted income (loss) per common share	$ (1.25)	$ (1.45)	$ (0.70)	$ (0.35)	$ (0.39)
Weighted average number of common shares—basic and diluted	407,116,144	406,839,997	403,356,174	376,603,520	349,342,050

(1) No income tax benefit has been reflected since a full valuation allowance has been established against the deferred tax asset that would have been generated as a result of the operating results.

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Consolidated Balance Sheet Information:

	As of December 31,				
	2014	2013	2012	2011	2010
			($ in thousands)		
Cash and cash equivalents(1)	$ 258,721	$ 192,460	$ 1,425,815	$ 292,546	$ 302,720
Short-term restricted funds	45,062	200,339	90,440	69,009	—
Short-term investments(2)	1,530,206	1,319,380	789,668	858,293	534,933
Total current assets	2,003,134	1,967,443	2,456,742	1,335,094	889,632
Total property, plant and equipment(3)	1,932,361	1,476,275	1,099,756	863,326	463,769
Long-term restricted funds	105,051	104,496	395,652	270,235	338,515
Long-term investments	326,047	14,661	36,267	47,232	40,003
Total assets	4,450,863	3,633,673	4,011,459	2,527,944	1,746,443
Total current liabilities(4)	303,601	340,967	160,956	238,069	24,559
Total long term liabilities(5)	2,032,996	1,163,560	1,161,285	210,961	2,850
Total stockholders' equity	2,114,266	2,129,146	2,689,218	2,078,914	1,719,034
Total liabilities and stockholders' equity	4,450,863	3,633,673	4,011,459	2,527,944	1,746,443

(1) The decrease in cash and cash equivalents from December 31, 2012 to December 31, 2013 was primarily due to the investment in held-to-maturity securities from the proceeds we received upon the issuance of our 2.625% convertible senior notes due 2019 in December 2012. The increase in cash and cash equivalents from December 31, 2011 to December 31, 2012 was due to the proceeds that we received on December 17, 2012 from the issuance of our 2.625% convertible senior notes due 2019. These proceeds were temporarily held in money market funds as of December 31, 2012.

(2) The increase in short-term investments from December 31, 2013 to December 31, 2014 was attributable to the investment of the proceeds from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The increase in short-term investments from December 31, 2012 to December 31, 2013 was attributable to the investment of the proceeds from the issuance of our 2.625% convertible senior notes due 2019 in December 2012. The increase in investments from December 31, 2010 to December 31, 2011 was attributed to the investment of the proceeds from the equity offering of common stock during 2011.

(3) The increase from December 31, 2013 to December 31, 2014 reflects the capitalized costs for the Anchor #1 exploration well, the Orca #2 appraisal well, and the Heidelberg development costs. The increase from December 31, 2012 to December 31, 2013 primarily reflects the capitalized costs for the Mavinga #1, Lontra #1, Bicuar #1A, Orca #1 and Diaman #1B exploration wells. The increase from December 31, 2011 to 2012 reflects acquisition of unproved leases in the U.S. Gulf of Mexico and the capitalized costs for the Heidelberg #3 and Cameia #2 appraisal wells and the North Platte #1 exploration well. The increase from December 31, 2010 to December 31, 2011 reflects the acquisition costs of Block 20 offshore Angola.

(4) The increase in current liabilities at December 31, 2013 was due to year-end accruals for exploration costs primarily in West Africa and the short-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21. The decrease in current liabilities at December 31, 2012 was primarily attributed to the payment of certain bonus obligations for Block 20 during 2012. The increase in current liabilities at December 31, 2011 consists of year-end accruals for exploration costs in the U.S. Gulf of Mexico and West Africa and the short-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21.

(5) The significant increase in long-term liabilities from December 31, 2013 to December 31, 2014 reflects the issuance of $1.3 billion aggregate principal amount of the 3.125% convertible senior

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notes due 2024 on May 13, 2014. The significant increase in long-term liabilities from December 31, 2011 to December 31, 2012 reflects the issuance of $1.38 billion aggregate principal amount of the 2.625% convertible senior notes due 2019 on December 17, 2012. The increase in long-term liabilities at December 31, 2011 reflects the long-term portion of the social and bonus payment obligations for Blocks 9, 20 and 21.

Consolidated Statement of Cash Flows Information:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	($ in thousands)				
Net cash provided by (used in):					
Operating activities	$ (64,526)	$ (216,368)	$ (140,397)	$ (57,795)	$ (133,264)
Investing activities	(1,138,393)	(1,015,995)	(564,761)	(430,391)	(758,372)
Financing activities	1,269,180	(992)	1,838,427	478,012	101,256

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements," and the other matters set forth in this Annual Report on Form 10-K. The following discussion of our financial condition and results of operations should be read in conjunction with our financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K, as well as the information presented under "Selected Financial Data." Due to the fact that we have not generated any revenues, we believe that the financial information contained in this Annual Report on Form 10-K is not indicative of, or comparable to, the financial profile that we expect to have once we begin to generate revenues. Except to the extent required by law, we undertake no obligation to update publicly any forward-looking statements for any reason, even if new information becomes available or other events occur in the future.

We are an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa. Since our founding in 2005, our oil-focused, below-salt exploration efforts have been successful in each of our three operating areas, resulting in ten discoveries out of the seventeen exploration prospects drilled. These ten discoveries consist of North Platte, Heidelberg, Shenandoah and Anchor in the U.S. Gulf of Mexico; Cameia, Lontra, Mavinga, Bicuar and Orca offshore Angola; and Diaman offshore Gabon. In addition, we have an interest in the Yucatan discovery in the U.S. Gulf of Mexico.

Factors Affecting Comparability of Future Results

You should read this management's discussion and analysis of our financial condition and results of operations in conjunction with our historical financial statements included elsewhere in this Annual Report on Form 10-K. Below are the period-to-period comparisons of our historical results and the analysis of our financial condition. In addition to the impact of the matters discussed in "Risk Factors," our future results could differ materially from our historical results due to a variety of factors, including the following:

Success in the Discovery and Development of Oil and Gas Reserves. Because we have no operating history in the production of oil and gas, our future results of operations and financial condition will be directly affected by our ability to discover and develop reserves through our drilling activities. The calculation of our geological and petrophysical estimates is complex and imprecise, and it is possible that our future exploration will not result in additional discoveries, and, even if we are able to

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successfully make such discoveries, there is no certainty that the discoveries will be commercially viable to produce. Our results of operations will be adversely affected in the event that our estimated oil and gas asset base does not result in reserves that may eventually be commercially developed.

Oil and Gas Revenue. We have not yet commenced production activities. If and when we do commence production, we expect to generate revenue from such production. No oil and gas revenue is reflected in our historical financial statements.

Production Costs. We have not yet commenced production activities. If and when we do commence production, we will incur production costs. Production costs are the costs incurred in the operation of producing and processing our production and are primarily comprised of lease operating expense, workover costs and production and ad valorem taxes. No production costs are reflected in our historical financial statements.

General and Administrative Expenses. These costs include expenses associated with our staff costs, information technology, rent, travel, annual and quarterly reporting, investor relations, registrar and transfer agent fees, incremental insurance costs, and accounting and legal services.

Depreciation, Depletion and Amortization. We have not yet commenced production activities. If and when we do commence production, we will amortize the costs of successful exploration, appraisal, drilling and field development using the unit-of-production method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved and unproved leasehold properties and associated asset retirement costs will be amortized using the unit-of-production method based on total estimated proved developed and undeveloped reserves. No depletion of oil and gas properties is reflected in our historical financial statements.

Demand and Price. The demand for oil and gas is susceptible to volatility related to, among other factors, policy decisions by oil-producing nations, the level of global economic activity and may also fluctuate depending on the performance of specific industries. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for oil and gas we expect to produce. Since we have not generated revenues, these key factors will only affect our financial statements when we produce and sell hydrocarbons.

We expect to earn income from:

- domestic and international sales, which consist of sales of oil and natural gas;
- sales to international markets; and
- other sources, including services, investment income and foreign exchange gains.

We expect that our expenses will include:

- costs of sales (which are composed of production costs, insurance, and costs associated with the operation of our wells);
- maintenance and repair of property and equipment;
- costs of acquiring new leases or licenses;
- costs of acquiring seismic data;
- depreciation, amortization and impairment of fixed assets;
- depletion of oilfields;
- exploration costs;

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- selling expenses (which include expenses relating to the transportation, marketing and distribution of our products) and general and administrative expenses; and
- interest expense and foreign exchange losses.

We expect that fluctuations in our financial condition and results of operations will be driven by a combination of factors, including:

- the volumes of oil and natural gas we produce and sell;
- changes in the domestic and international prices of oil and natural gas, which are denominated in U.S. dollars;
- fluctuations in the royalty rates on the leases that we hold;
- our success in future bidding rounds for licenses, leases and concessions;
- political and economic conditions in the countries in which we operate; and
- the amount of taxes and duties that we are required to pay with respect to our future operations, by virtue of our status as a U.S. company and our involvement in the oil and gas industry.

Results of Operations

We operate our business in two geographic segments: the U.S. Gulf of Mexico and West Africa. The discussion of the results of operations and the period-to-period comparisons presented below for each operating segment and our consolidated operations analyzes our historical results. The following discussion may not be indicative of future results.

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Fiscal year ended December 31, 2014 as compared to year ended December 31, 2013

	Year Ended December 31, 2014	2013	Increase (Decrease)	Percentage Change
	($ in thousands)			
U.S. Gulf of Mexico Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	31,531	48,688	(17,157)	(35)%
Dry hole expense and impairment	133,223	207,039	(73,816)	(36)%
General and administrative	71,767	72,777	(1,010)	(1)%
Depreciation and amortization	1,693&sbsp;	1,328	365	27%
Total operating costs and expenses	**238,214**	**329,832**	**(91,618)**	**(28)%**
Operating income (loss)	**(238,214)**	**(329,832)**	**(91,618)**	**(28)%**
West Africa Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	54,036	25,525	28,511	112%
Dry hole expense and impairment	103,707	144,011	(40,304)	(28)%
General and administrative	43,093	32,770	10,323	32%
Depreciation and amortization	2,891	546	2,345	429%
Total operating costs and expenses	**203,727**	**202,852**	**875**	**0%**
Operating income (loss)	**(203,727)**	**(202,852)**	**875**	**0%**
Consolidated Operations:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	85,567	74,213	11,354	15%
Dry hole expense and impairment	236,930	351,050	(114,120)	(33)%
General and administrative	114,860	105,547	9,313	9%
Depreciation and amortization	4,584	1,874	2,710	145%
Total operating costs and expenses	**441,941**	**532,684**	**(90,743)**	**(17)%**
Operating income (loss)	**(441,941)**	**(532,684)**	**(90,743)**	**(17)%**
Other income (expense)				
Gain (loss) on sale of assets	(12)	2,993	(3,005)	(100)%
Interest income	5,958	6,043	(85)	(1)%
Interest expense	(74,768)	(65,376)	9,392	14%
Total other income (expense)	**(68,822)**	**(56,340)**	**12,482**	**22%**
Net income (loss) before income tax	**(510,763)**	**(589,024)**	**(78,261)**	**(13)%**
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$ (510,763)**	**$ (589,024)**	**$ (78,261)**	**(13)%**

U.S. Gulf of Mexico Segment:

Oil and gas revenue. We have not yet commenced production activities in the U.S. Gulf of Mexico. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2014 and 2013, respectively.

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Operating costs and expenses. Our operating costs and expenses for our U.S. Gulf of Mexico operations consisted of the following during the years ended December 31, 2014 and 2013:

Seismic and exploration. Seismic and exploration costs decreased by approximately $17.2 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease was primarily due to a $20.2 million decrease in seismic costs offset by the increase of $0.7 million in delay rental and $2.3 million in exploration expenses attributed primarily to standby costs on the Ensco 8503 incurred during January 2014.

Dry hole expense and impairment. Dry hole expense and impairment decreased by $73.8 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease is due to impairment of unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2014	2013	Increase (Decrease)
	($ in thousands)		
Impairment of Unproved leasehold:			
Ardennes prospect	$ —	$ 29,122	$ (29,122)
Aegean prospect	—	38,499	(38,499)
Other leasehold(1)	57,308	10,002	47,306
Amortization of leasehold with carrying value under $1 million	10,662	9,417	1,245
Dry Hole Expense:			
Ligurian #1 exploration well	46	631	(585)
Ardennes #1 exploration well	(133)	66,133	(66,266)
Aegean #1 exploration well	3,920	53,235	(49,315)
Anchor #1 exploration well	38,075	—	38,075
Yucatan #2 exploration well	17,313	—	17,313
Shenandoah by-pass #3 appraisal well	5,032	—	5,032
Other Impairments:			
Obsolete inventory	1,000	—	1,000
	$ 133,223	$ 207,039	$ (73,816)

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs decreased by $1.0 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The decrease in general and administrative costs during this period was primarily attributed to a $10.2 million increase in staff related expenses which includes non-cash equity compensation and a $3.0 million increase in insurance and office support costs, offset by a decrease of $3.7 million in legal and consulting fees and an increase of $10.5 million in recoveries from partners associated with drilling activities.

Depreciation and amortization. Depreciation and amortization did not materially change during the year ended December 31, 2014 as compared to the year ended December 31, 2013.

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West Africa Segment:

Oil and gas revenue. We have not yet commenced production activities in West Africa. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2014 and 2013.

Operating costs and expenses. Our operating costs and expenses for our West Africa operations consisted of the following during the years ended December 31, 2014 and 2013:

Seismic and exploration. Seismic and exploration costs increased by approximately $28.5 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The increase was primarily attributed to an increase of $37.6 million in exploration expenses, offset by a decrease of $9.1 million in seismic costs. During the year ended December 31, 2014, seismic and exploration expenses included $34.4 million in standby costs associated with the Ocean Confidence and SSV Catarina drilling rig, $5.6 million associated with the early contract termination of support vessels and helicopters, $1.4 million in custom fees and freight charges and $12.6 million in seismic costs. During the year ended December 31, 2013, seismic and exploration expenses included $3.8 million in standby costs associated with acceptance testing and drilling equipment issues with the Ocean Confidence drilling rig and $21.7 million in seismic costs.

Dry hole expense and impairment. Dry hole expense and impairment decreased by $40.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The decrease is due to dry hole expense during the years ended December 31, 2014 and 2013 as reflected in the following table:

	Year Ended December 31,		
	2014	2013	Increase (Decrease)
		($ in thousands)	
Impairment of Unproved Leasehold:			
Block 9 prospect	$ 2,500	$ —	$ 2,500
Dry Hole Expense(1):			
Cameia #2 drill stem test(2)	2,046	81,607	(79,561)
Diaman #1 exploration well	—	17,066	(17,066)
Mavinga #1 exploration well	—	12,520	(12,520)
Lontra #1 exploration well	—	32,247	(32,247)
Loengo #1 exploration well	52,672	—	52,672
Mupa #1 exploration well	46,489	—	46,489
Other Impairment:			
Obsolete inventory	—	571	(571)
	$ 103,707	$ 144,011	$ (40,304)

(1) The amounts listed above and charged to dry hole expense for our Lontra #1 and Mavinga #1 exploration wells only relate to the costs associated with drilling the lowest intervals beneath the pay zones. The majority of the well costs associated with our Lontra #1 and Mavinga #1 exploration wells were capitalized as of December 31, 2013 and will remain suspended pending further evaluation of these wells. The amounts listed above for our Cameia #2 Drill Stem Test and Diaman #1, Loengo #1 and Mupa #1 exploration wells were abandoned and were charged to dry hole expense.

(2) The amounts listed above and charged to dry hole expense for the Cameia #2 drill stem test only relate to the costs associated with the testing of a geologic zone beneath the pay zone reservoirs encountered by the Cameia #1 and Cameia #2 wells.

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General and administrative. General and administrative costs increased by $10.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in general and administrative costs during this period was primarily attributed to a $1.4 million increase in staff related expenses in Angola and $23.5 million in contractual charges from partners for overhead and technical charges, offset by a $13.2 million decrease in other office related expenses and a $1.4 million decrease for contractors and consulting services incurred in support of West Africa operations during the year ended December 31, 2014.

Depreciation and amortization. Depreciation and amortization increased by $2.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily attributed to the depreciation of $9.8 million of running tools and equipment over three years' estimated useful lives. We purchased the running tools and equipment for $3.5 million and $6.3 million during the years ended December 31, 2014 and 2013, respectively.

Consolidated:

Other income (expense). Other income (expense) increased by $12.5 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily due to a $9.4 million increase in interest expense associated with the issuance of the 3.125% convertible senior notes due 2024 on May 13, 2014 and a $3.1 million decrease in other income attributed to gain on sale of other assets during the year ended December 31, 2013.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $568.0 million and $461.6 million with a corresponding full valuation of $568.0 million and $461.6 million for the years ended December 31, 2014 and 2013, respectively.

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Fiscal year ended December 31, 2013 as compared to year ended December 31, 2012

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase (Decrease)	Percentage Change
	($ in thousands)			
U.S. Gulf of Mexico Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	48,688	32,874	15,814	48%
Dry hole expense and impairment	207,039	134,085	72,954	54%
General and administrative	72,777	63,270	9,507	15%
Depreciation and amortization	1,328	967	361	37%
Total operating costs and expenses	**329,832**	**231,196**	**98,636**	43%
Operating income (loss)	**(329,832)**	**(231,196)**	**98,636**	43%
West Africa Segment:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	25,525	28,709	(3,184)	(11)%
Dry hole expense and impairment	144,011	—	144,011	—%
General and administrative	32,770	24,693	8,077	33%
Depreciation and amortization	546	230	316	137%
Total operating costs and expenses	**202,852**	**53,632**	**149,220**	278%
Operating income (loss)	**(202,852)**	**(53,632)**	**149,220**	278%
Consolidated Operations:				
Oil and gas revenue	$ —	$ —	$ —	—%
Operating costs and expenses				
Seismic and exploration	74,213	61,583	12,630	21%
Dry hole expense and impairment	351,050	134,085	216,965	162%
General and administrative	105,547	87,963	17,584	20%
Depreciation and amortization	1,874	1,197	677	57%
Total operating costs and expenses	**532,684**	**284,828**	**247,856**	87%
Operating income (loss)	**(532,684)**	**(284,828)**	**247,856**	87%
Other income (expense)				
Gain on sale of assets	2,993	—	2,993	—%
Interest income	6,043	5,041	1,002	20%
Interest expense	(65,376)	(3,212)	62,164	1935%
Total other income (expense)	**(56,340)**	**1,829**	**58,169**	3180%
Net income (loss) before income tax	**(589,024)**	**(282,999)**	**306,025**	108%
Income tax expense (benefit)	—	—	—	—
Net income (loss)	**$ (589,024)**	**$ (282,999)**	**$ 306,025**	108%

U.S. Gulf of Mexico Segment:

Oil and gas revenue. We have not yet commenced production activities in the U.S. Gulf of Mexico. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2013 and 2012.

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Operating costs and expenses. Our operating costs and expenses for our U.S. Gulf of Mexico operations consisted of the following during the years ended December 31, 2013 and 2012:

Seismic and exploration. Seismic and exploration costs increased by approximately $15.8 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase was primarily due to a $16.6 million increase in seismic costs and a $0.3 million increase in delay rentals, offset by the decrease of $1.1 million in exploration expenses which were primarily attributable to standby and regulatory acceptance costs incurred for Ensco 8503 drilling rig during the year ended December 31, 2012. There were no standby costs incurred for the Ensco 8503 drilling rig during the year ended December 31, 2013.

Dry hole expense and impairment. Dry hole expense and impairment increased by $73.0 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase is due to impairment of unproved leasehold properties and dry hole expense written off against exploration wells as reflected in the following table:

	Year Ended December 31,		
	2013	2012	Increase (Decrease)
		($ in thousands)	
Impairment of Unproved leasehold:			
Ligurian prospect	$ —	$ 41,861	$ (41,861)
Ardennes prospect	29,122	—	29,122
Aegean prospect	38,499	—	38,499
Other leasehold(1)	10,002	8,298	1,704
Amortization of leasehold with carrying value under $1 million	9,417	10,007	(590)
Dry Hole Expense:			
Ligurian #1 exploration well	631	8,100	(7,469)
Ligurian #2 exploration well	—	48,994	(48,994)
Heidelberg #3 appraisal well side track	—	4,109	(4,109)
Shenandoah #2 appraisal well	—	12,716	(12,716)
Ardennes #1 exploration well	66,133	—	66,133
Aegean #1 exploration well	53,235	—	53,235
	$ 207,039	$ 134,085	$ 72,954

(1) Other leasehold includes certain unproved oil and gas leases for properties in the U.S. Gulf of Mexico with carrying value greater than $1 million that we have no exploration activity planned, based on our three-year exploration plan, during the remaining term of the leases.

General and administrative. General and administrative costs increased by $9.5 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in general and administrative costs during this period was primarily attributed to an $11.4 million increase in staff related expenses which includes non-cash equity compensation, a $12.9 million increase in legal and other consulting fees, an $8.0 million increase in insurance and office support costs, offset by an increase of $22.8 million in recoveries from partners due to the increase in drilling activities.

Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

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West Africa Segment:

Oil and gas revenue. We have not yet commenced production activities in West Africa. Therefore, we did not realize any oil and gas revenue during the years ended December 31, 2013 and 2012.

Operating costs and expenses. Our operating costs and expenses for the West Africa operations consisted of the following during the years ended December 31, 2013 and 2012:

Seismic and exploration. Seismic and exploration costs decreased by approximately $3.2 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The decrease of $3.2 million was primarily attributed to an increase of $4.7 million in seismic costs, offset by a decrease of $7.9 million in other exploration costs. During the year ended December 31, 2012, approximately $11.7 million in standby costs were incurred associated with the drilling of the Cameia #2 appraisal well as compared to $3.6 million in standby costs incurred in early 2013 associated with drilling equipment issues with the Ocean Confidence drilling rig.

Dry hole expense and impairment. Dry hole expense and impairment increased by $144.0 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. The increase is due to dry hole expense during the years ended December 31, 2013 as reflected in the following table:

	Year Ended December 31,		
	2013	2012	Increase (Decrease)
	($ in thousands)		
Dry Hole Expense(1):			
Cameia #2 drill stem test(2)	$ 81,607	$ —	$ 81,607
Diaman #1 exploration well	17,066	—	17,066
Mavinga #1 exploration well	12,520	—	12,520
Lontra #1 exploration well	32,247	—	32,247
Other Impairment:			
Obsolete inventory	571	—	571
	$ 144,011	$ —	$ 144,011

(1) The amounts listed above and charged to dry hole expense for our Lontra #1 and Mavinga #1 exploration wells only relate to the costs associated with drilling the lowest intervals beneath the pay zones. The majority of the well costs associated with our Lontra #1 and Mavinga #1 exploration wells have been capitalized as of December 31, 2013 and will remain suspended pending further evaluation of these wells. The amounts listed above for our Diaman #1 exploration well were charged to dry hole expense because this well encountered mechanical problems early in the drilling process and was re-spud as the Diaman #1B exploration well.

(2) The amounts listed above and charged to dry hole expense for the Cameia #2 drill stem test only relate to the costs associated with the testing of a geologic zone beneath the pay zone reservoirs encountered by the Cameia #1 and Cameia #2 wells.

General and administrative. General and administrative costs increased by $8.1 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in general and administrative costs during this period was primarily attributed to a $2.1 million increase in staff related expenses in Angola, a $4.5 million increase in other office related expenses and a $1.5 million increase for contractors and consulting services incurred in support of West Africa operations during the year ended December 31, 2013.

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Depreciation and amortization. Depreciation and amortization did not change significantly during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Consolidated:

Other income (expense). Other income (expense) increased by $58.2 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase was primarily due to the increase of $1.0 million from interest earned in investment securities and $3.0 million in gain on sale of other assets, offset by $62.2 million recognized for the interest expense associated with our 2.625% convertible senior notes due 2019 during the year ended December 31, 2012.

Income taxes. As a result of net operating losses, for income tax purposes, we recorded a net deferred tax asset of $568.0 million and $461.6 million with a corresponding full valuation of $568.0 million and $269.6 million for the years ended December 31, 2013 and 2012, respectively.

Liquidity and Capital Resources.

Our Heidelberg project was sanctioned in mid-2013, and the operator currently estimates first production from Heidelberg in the first half of 2016. We continue to advance our Cameia project through the project development life-cycle. On May 28, 2014, we submitted the initial integrated field development plan for our Cameia project on Block 21 offshore Angola for approval by Sonangol and the Angola Ministry of Petroleum. Given the current commodity price environment, we believe an opportunity exists to review the project design concept and projected capital expenditures in order to optimize the cost and scale of the Cameia development and production facilities prior to formal project sanction. During 2015, we intend to pursue project cost reductions in light of the current weakness in the market for goods and services utilized in major offshore development projects. We remain committed to progressing the Cameia development towards project sanction and production, and, to that end, we plan to spud the first of several planned Cameia development wells in the first quarter of 2015. We expect to achieve formal project sanction of Cameia by year-end 2015, and first production from Cameia will likely occur in 2018. The occurrence and timing of project sanction and first production from Cameia is subject to obtaining adequate financing and the approval of a revised integrated field development plan by Sonangol and the Angola Ministry of Petroleum.

Until substantial production is achieved, our primary sources of liquidity are expected to be cash on hand, amounts paid pursuant to the terms of our Total alliance and funds from any future equity and debt financings, asset-based ventures and asset monetizations.

We expect to incur substantial expenditures and generate significant operating losses as we continue to:

- evaluate each of our discoveries through project appraisal and potential development towards first production and cash flow;
- continue our exploration activity on our existing acreage;
- seek the renewal of our worldwide exploration portfolio in locations applicable to our deepwater and below-salt exploration strength; and
- incur expenses related to operating as a public company and compliance with regulatory requirements.

Our future financial condition and liquidity will be impacted by, among other factors, our ability to obtain financing, oil and gas prices, the success of our project development and exploration efforts, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed with which we can bring such discoveries to production, whether and to what

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extent we invest in additional oil leases and concessional licenses, and the actual cost of exploration, appraisal and development of our prospects.

As of December 31, 2014, we had approximately $2.3 billion in liquidity, which includes cash and cash equivalents, short-term restricted cash, short-term investments, long-term restricted cash and long-term investments. This amount does not include amounts Total is obligated to pay us pursuant to the terms of our U.S. Gulf of Mexico alliance. We expect to expend approximately $800 to $900 million for our capital and operating expenditures in 2015. Given our exploration success, our focus has now shifted towards selectively developing our discoveries with the aim to turn them into production. Thus, we currently expect to allocate approximately 80% of our planned 2015 capital and operating expenditure budget toward project appraisal and development activities. Our capital and operating expenditures were approximately $829 million for the full-year ended December 31, 2014. Our capital and operating expenditures exclude interest payments, Angolan social contributions and items amortized in future years' operations. We expect to use approximately $200 million for these items in 2015. We expect that our existing cash on hand will be sufficient to fund our planned exploration and appraisal drilling program and development activities at current working interests through at least 2016.

On February 19, 2015 we executed a commitment letter with Société Générale and certain of its affiliates for a limited recourse $150 million senior secured reserve-based loan facility to fund the majority of our share of the remaining Heidelberg field development costs. It is anticipated that the facility will be further syndicated. The commitments are subject to the negotiation and execution of definitive loan documentation and other customary conditions.

We are currently pursuing certain asset-based ventures and monetizations to fund our long-term project appraisal, development and exploration activities. We may also seek additional funding through equity and debt financings. Additional funding, including funding through any asset-based venture or monetization, may not be available to us on acceptable terms or at all. In addition, the terms of any financing may adversely affect the holdings or the rights of our existing stockholders. For example, if we raise additional funds by issuing additional equity securities, further dilution to our existing stockholders will result. If we are unable to obtain funding on a timely basis or on acceptable terms, we may be required to significantly curtail our exploration, appraisal and development activities. Any asset-based venture or monetization may also require us to relinquish rights to some of our development projects or exploration prospects which we would otherwise develop on our own, or with a majority working interest.

Cash Flows

	Year Ended December 31.		
	2014	2013	2012
		($ in thousands)	
Net cash provided by (used in):			
Operating Activities	$ (64,526)	$ (216,368)	$ (140,397)
Investing Activities	(1,138,393)	(1,015,995)	(564,761)
Financing Activities	1,269,180	(992)	1,838,427

Operating activities. Net cash of $64.5 million, $216.4 million and $140.4 million used in operating activities during 2014, 2013 and 2012, respectively, were primarily related to cash payments for seismic expenses, exploration expenses and inventory incurred in the U.S. Gulf of Mexico and in West Africa

Investing activities. Net cash used in investing activities in 2014 was approximately $1.1 billion, compared with net cash used in investing activities of approximately $1.0 billion and $564.8 million in 2013 and 2012, respectively. The net cash used in 2014 primarily relates to capital expenditures incurred for the Shenandoah #3 appraisal well, Shenandoah #3 appraisal well by-pass, Anchor #1,

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Anchor #2 and Yucatan #2 exploration wells and the Heidelberg development project in the deepwater U.S. Gulf of Mexico and the Cameia #3 appraisal well, Loengo #1 and Mupa #1 exploration wells offshore Angola, and purchase of investment securities from the net proceeds of the 3.125% convertible senior notes due 2024. The net cash used in 2013 primarily relates to capital expenditures relating to the Ardennes #1 and Aegean #1 exploration wells in the deepwater U.S. Gulf of Mexico and the Mavinga #1, Lontra #1, Bicuar #1A and Diaman #1B exploration wells offshore Angola. The net cash used in 2012 primarily relates to capital expenditures for the North Platte #1 exploration well in the deepwater U.S. Gulf of Mexico and the Cameia #1 exploration well and Cameia #2 appraisal well offshore Angola.

Financing activities. Net cash provided by financing activities in 2014 was approximately $1.3 billion, compared with net cash used by financing activities of approximately $1.0 million and net cash provided by financing activities of $1.8 billion in 2013 and 2012, respectively. The $1.3 billion in net cash provided by financing activities in 2014 relates to net proceeds we received from the issuance of our 3.125% convertible senior notes due 2024 in May 2014. The $1.0 million net cash used in financing activities relates to the debt issuance costs paid during 2013. The $1.8 billion in net cash provided by financing activities in 2012 was attributed to the net proceeds we received from the issuance of our 2.625% convertible senior notes due 2019 in December 2012 and our public offering of common stock in February 2012.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2014:

	Payments Due By Year						
	2015	2016	2017	2018	2019	Thereafter	Total
	($ in thousands)						
Drilling Rig and Related Contracts	$ 544,559	$ 299,702	$ 208,104	$ 17,104	$ —	$ —	$ 1,069,469
Operating Leases	9,755	4,801	2,309	2,369	2,405	5,626	27,265
Lease Rentals(1)	7,353	5,460	5,007	2,282	1,973	7,223	29,298
Social and Work Program Payment Obligations(2)	55,999	84,729	5,714	5,714	—	—	152,156
Long-term Debt Obligations(3):							
Principal	—	—	—	—	1,380,000	1,300,000	2,680,000
Interest	76,850	76,850	76,850	76,850	76,850	177,596	561,846
Total	**$ 694,516**	**$ 471,542**	**$ 297,984**	**$ 104,319**	**$ 1,461,228**	**$ 1,490,445**	**$ 4,520,034**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to our U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

(2) Includes our contractual payment obligations for (i) social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that we were and are contractually obligated to pay in consideration for the Angolan government granting us the licenses to explore for and develop hydrocarbons offshore Angola and (ii) our remaining work program obligations on Block 9 offshore Angola. Pursuant to the terms of the RSAs for Blocks 9 and 21 and the PSC for Block 20, we are not required to pay annual rental payments to maintain the licenses from year to year.

(3) Represents principal amounts of our 2.625% convertible senior notes due 2019 and our 3.125% convertible senior notes due 2024 and interest payable semi-annually in arrears.

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In the future, we may be party to additional contractual arrangements including but not limited to arrangements listed below, which will subject us to further contractual obligations:

- credit facilities and other debt instruments;
- contracts for the lease of additional drilling rigs;
- contracts for the provision of production facilities;
- infrastructure construction contracts; and
- long term oil and gas property lease arrangements.

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We plan to follow the "sales" (or cash) method of accounting for oil and gas revenues. Under this method, we will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the year ended December 31, 2014, no revenues have been recognized in our financial statements.

We recognize interest income on bank balances and deposits on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however we periodically assess the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believe that the credit risk is minimal.

Investments. We adopted a policy on accounting for our investments, which consist entirely of debt securities based on the accounting guidance relating to "*Accounting for Certain Investments in Debt and Equity Securities.*" The debt securities are carried at amortized costs and classified as held-to-maturity as we have the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Money market funds and certificates of deposit are carried at face value.

We conduct a regular assessment of our debt securities with unrealized losses to determine whether securities have other-than-temporary impairment. This assessment considers, among other

factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether we intend to sell or whether it is more likely than not that we will be required to sell the debt securities.

Property, Plant and Equipment. We use the "successful efforts" method of accounting for our oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes are capitalized and amortized over the proved developed reserves on a units-of-production basis. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed on an individual basis periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological, and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Inventory. Inventories consist of various tubular products that will be used in our drilling programs. The inventory is stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

Income Taxes. We applied the liability method of accounting for income taxes in accordance with accounting guidance relating to "*Income Taxes*" as clarified by *Accounting for Uncertainty in Income Taxes*. Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since we are in development stage and there can be no assurance that we will generate any earnings or any specific level of earnings in future years, we will establish a valuation allowance for deferred tax assets (net of liabilities).

Use of Estimates. The preparation of our consolidated financial statements in conformity with United States generally accepted accounting principles requires us to make estimates and assumptions that impact our reported assets and liabilities, disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include: (i) accruals related to expenses, (ii) assumptions used in estimating fair value of equity-based awards and the fair value of the liability component of the convertible senior notes and (iii) assumptions used in impairment testing. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Estimates of Proved Oil & Natural Gas Reserves. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As of December 31, 2014, we have proved undeveloped reserves in the U.S. Gulf of Mexico. Estimated reserve quantities and future cash flows were estimated by independent

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petroleum consultants and prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. The accuracy of these reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating cost, severance taxes, development cost and workover cost, all of which may in fact vary considerably from actual results;
- the accuracy of various mandated economic assumptions (such as the future prices of oil and natural gas); and
- the judgments of the persons preparing the estimates.

Asset Retirement Obligations. We currently do not have any oil and natural gas production or any legal obligations to incur decommissioning costs. Should such production occur in the future, we expect to have significant obligations under our lease agreements and federal regulation to remove our equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations ("ARO") are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Pursuant to the accounting guidance relating to "*Asset Retirement Obligations,*" we are required to record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties representing asset retirement costs on our balance sheet. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, we will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the consolidated statement of operations.

Earnings (Loss) Per Share. Basic earnings (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. Diluted earnings (loss) per share incorporate the potential dilutive impact of our 2.625% convertible senior notes due 2019, our 3.125% convertible senior notes due 2024, stock options, unvested restricted stock and restricted stock units outstanding during the periods presented, unless their effect is anti-dilutive. In addition, we apply the if-converted method to our convertible debt instruments, the effect of which is that conversion will not be assumed for purposes of computing diluted earnings (loss) per share if the effect would be anti-dilutive.

Equity-Based Compensation. We account for stock-based compensation at fair value. We grant various types of stock-based awards including stock options, restricted stock and performance-based

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awards. The fair value of stock option awards is determined by using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of our common stock on the grant date. We record compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when we determine that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risks" refers to the risk of loss arising from changes in commodity prices, interest rates, foreign currency exchange rates, and other relevant market risks. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments will be entered into for purposes of risk management and not for speculation.

Due to the historical volatility of commodity prices, if and when we commence production, we may enter into various derivative instruments to manage our exposure to volatility of commodity market prices. We may use options (including floors and collars) and fixed price swaps to mitigate the impact of downward swings in commodity prices to our cash flow. All contracts will be settled with cash and would not require the delivery of physical volumes to satisfy settlement. While in times of higher commodity prices this strategy may result in our having lower net cash inflows than we would otherwise have if we had not utilized these instruments, management believes the risk reduction benefits of such a strategy would outweigh the potential costs.

We may borrow under fixed rate and variable rate debt instruments that give rise to interest rate risk. Our objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing our costs of capital.

Item 8. ***Financial Statements and Supplementary Data***

The information required is included in this report as set forth in the "Index to Consolidated Financial Statements" on page F-1 to this Annual Report on Form 10-K.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None

Item 9A. ***Controls and Procedures***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2014, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and our Chief Financial Officer ("CFO"), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and CFO, does not expect that our

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disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Because of the inherent limitation in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2014.

Management's Report on Internal Control over Financial Reporting

The information required to be furnished pursuant to this item is set forth under the caption "Management's Report on Internal Control over Financial Reporting" in Item 8 of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

The information required to be furnished pursuant to this item is set forth under the caption "Report of Independent Registered Public Accounting Firm" in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There have been no other changes in our internal control over financial reporting during the fourth quarter ended December 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item is set forth under the captions "Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement (the "2015 Proxy Statement") for our annual meeting of stockholders to be held on April 30, 2015, which sections are incorporated herein by reference.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this Annual Report on Form 10-K.

Item 11. ***Executive Compensation***

The information required by this item is set forth in the sections entitled "Election of Directors—Director Compensation," "Executive Compensation" and "Corporate Governance" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by this item is set forth in the sections entitled "Security Ownership of Certain Beneficial Owners and Management" and "Executive Compensation—Equity Compensation Plan Information" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

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Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is set forth in the section entitled "Corporate Governance" and "Certain Relationships and Related Transactions" in the 2015 Proxy Statement, which sections are incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services***

The information required by this item is set forth in the section entitled "Ratification of Appointment of Independent Auditors" in the 2015 Proxy Statement, which section is incorporated herein by reference.

GLOSSARY OF SELECTED OIL AND GAS TERMS

"2-D seismic data"	Two-dimensional seismic data, being an interpretive data that allows a view of a vertical cross-section beneath a prospective area.
"3-D seismic data"	Three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic data.
"Angola PAL"	Angola Petroleum Activities Law.
"Appraisal well"	A well drilled after an exploration well to gain more information on the drilled reservoirs.
"Barrel"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"Bbl"	Barrel.
"Bcf"	Billion cubic feet.
"Below-salt"	A term encompassing both subsalt, as used in connection with the U.S. Gulf of Mexico, and pre-salt, as used in connection with offshore West Africa.
"Block 9 RSA"	Risk Service Agreement governing Block 9 offshore Angola.
"Block 21 RSA"	Risk Service Agreement governing Block 21 offshore Angola.
"Block 20 PSC"	Production Sharing Contract governing Block 20 offshore Angola.
"Blowouts"	Blowout is the uncontrolled release of a formation fluid, usually gas, from a well being drilled, typically for petroleum production.
"BOEPD"	Barrels of oil equivalent per day. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"BOPD"	Barrels of oil per day.
"Btu"	British thermal unit.
"Completion"	The procedure used in finishing and equipping an oil or natural gas well for production.

"Delay rental"	Payment made to the lessor under a non-producing oil and natural gas lease at the beginning or end of each year to continue the lease in force for another year during its primary term.
"Development"	The phase in which an oil field is brought into production by drilling development wells and installing appropriate production systems.
"Development well"	A well drilled to a known formation in a discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.
"Drilling and completion costs"	All costs, excluding operating costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all labor and other construction and installation costs incident thereto, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, costs of plugging back, deepening, rework operations, repairing or performing remedial work of any type, costs of plugging and abandoning any well participated in by us, and reimbursements and compensation to well operators.
"Dry hole"	An exploration, appraisal or development well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
"DST"	Drill stem test
"E&P"	Exploration and production.
"EPSC"	Exploration and Production Sharing Contract.
"Exploration well"	A well drilled either (a) in search of a new and as yet undiscovered pool of oil or natural gas or (b) with the hope of significantly extending the limits of a pool already developed.
"Farm-out"	An agreement whereby the owner of the leasehold or working interest agrees to assign a portion of his interest in certain acreage subject to the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment. Under a farm-out, the owner of the leasehold or working interest may retain some interest such as an overriding royalty interest, an oil and natural gas payment, offset acreage or other type of interest.
"Field"	A geographical area under which an oil or natural gas reservoir lies in commercial quantities.
"FERC"	Federal Energy Regulatory Commission
"FPSO"	Floating Production, Storage and Offloading system.
"Gathering system"	Pipelines and other facilities that transport oil from wells and bring it by separate and individual lines to a central delivery point for delivery into a transmission line or mainline.
"Gross acre"	An acre in which a working interest is owned. The number of gross acres is the total number of acres in which an interest is owned.

"Horizon"	A zone of a particular formation; that part of a formation of sufficient porosity and permeability to form a petroleum reservoir.
"IQE"	Independent Qualified Estimator.
"Leases"	Full or partial interests in oil or natural gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas upon payment of rental, bonus, royalty or any other payments.
"MBOE"	Thousand barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"MMBOE"	Million barrels of oil equivalent. Natural gas is converted on the basis of six Mcf of gas per one barrel of crude oil equivalent. This ratio reflects an energy content equivalency and not a price or revenue equivalency.
"Mcf"	Thousand cubic feet.
"MMBbls"	Million barrels.
"MMBtu"	Million British thermal units.
"MMCFD"	Million cubic feet per day.
"Natural gas"	Natural gas is a combination of light hydrocarbons that, in average pressure and temperature conditions, is found in a gaseous state. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.
"Net pay thickness"	The vertical extent of the effective hydrocarbon-bearing rock (expressed in feet). The net pay thickness encountered by an exploration well may differ from the mean net pay thickness of the prospect due to several factors, including the relative location of the exploration well on the structure, potential thickness variations that may occur across the prospect and the extent to which potential reservoir horizons are penetrated.
"NORM"	Naturally occurring radioactive materials.
"NSAI"	Netherland, Sewell & Associates, Inc.
"Oil and natural gas lease"	A legal instrument executed by a mineral owner granting the right to another to explore, drill, and produce subsurface oil and natural gas. An oil and natural gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee.
"OPEC"	Organization of the Petroleum Exporting Countries.
"Operator"	A party that has been designated as manager for exploration, drilling, and/or production on a lease. The operator is the party that is responsible for (a) initiating and supervising the drilling and completion of a well and/or (b) maintaining the producing well.

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"Play"	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.
"Porosity"	Porosity is the percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be a relic of deposition (primary porosity, such as space between grains that were not compacted together completely) or can develop through alteration of the rock (secondary porosity, such as when feldspar grains or fossils are preferentially dissolved from sandstones).
"Productive well"	A well that has been drilled to the targeted depth and proves, in our opinion, to be capable of producing either oil or gas in sufficient quantities that will justify completion as an oil or gas well.
"Prospect(s)"	Potential trap which may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of them fail neither oil nor natural gas will be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"PSA"	Production Sharing Agreement.
"PV-10"	Present value of future net pre-tax cash flows attributable to our estimated net proved reserves (after deducing future development and production costs), discounted at 10% per annum.
"Reservoir"	A subsurface body of rock having sufficient porosity and permeability to store and to allow for the mobility of fluids/hydrocarbons included in its pores.
"Royalty"	A fractional undivided interest in the production of oil and natural gas wells, or the proceeds therefrom to be received free and clear of all costs of development, operations or maintenance.
"RPC"	Reserves Process Chair.
"SEC"	United States Securities and Exchange Commission.
"Shut in"	To close the valves on a well so that it stops producing.
"Spud"	The very beginning of drilling operations of a new well, occurring when the drilling bit penetrates the surface utilizing a drilling rig capable of drilling the well to the authorized total depth.

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"Standardized Measure"	The present value of estimated future net cash inflows from proved oil and natural gas reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future net cash flows.
"Working interest"	An interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.
"Workover"	Operations on a producing well to restore or increase production.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

Cobalt International Energy, Inc.

(2) Financial Statement Schedule

Not applicable.

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(3) Exhibits

The following exhibits are filed with this Annual Report on Form 10-K or incorporated by reference:

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.2	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.3	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))

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Exhibit Number	Description of Document
10.4	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.5	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.6	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.7	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.8	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.10	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.11	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.12	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.13	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.14	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.15†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

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Exhibit Number	Description of Document
10.17†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.18†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.19†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.20†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.21†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.22†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.23†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.24†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.25†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.26†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.28†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.29†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.30†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.31†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))

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Exhibit Number	Description of Document
10.32†	Form of Restricted Stock Unit Award Notification under the Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.33†*	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield
10.34†*	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth
10.35†*	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter
10.36†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2015
10.37†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015
10.38†*	Form of Stock Appreciation Right Award Agreement under the Company's Long Term Incentive Plan
10.39†*	Form of Restricted Stock Unit Award Agreement under the Company's Long Term Incentive Plan
10.40†*	Form of Restricted Stock Award Agreement under the Company's Long Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Cobalt International Energy, Inc.

By: /s/ JOSEPH H. BRYANT

Name: Joseph H. Bryant
Title: *Chairman of the Board of Directors and Chief Executive Officer*

Dated: February 23, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ JOSEPH H. BRYANT Joseph H. Bryant	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 23, 2015
/s/ JOHN P. WILKIRSON John P. Wilkirson	Chief Financial Officer and Executive Vice President (Principal Financial Officer and Principal Accounting Officer)	February 23, 2015
/s/ JACK E. GOLDEN Jack E. Golden	Director	February 23, 2015
/s/ KAY BAILEY HUTCHISON Kay Bailey Hutchison	Director	February 23, 2015
/s/ JON A. MARSHALL Jon A. Marshall	Director	February 23, 2015
/s/ KENNETH W. MOORE Kenneth W. Moore	Director	February 23, 2015

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Signature	Title	Date
/s/ MYLES W. SCOGGINS Myles W. Scoggins	Director	February 23, 2015
/s/ WILLIAM P. UTT William P. Utt	Director	February 23, 2015
/s/ D. JEFF VAN STEENBERGEN D. Jeff van Steenbergen	Director	February 23, 2015
/s/ MARTIN H. YOUNG, JR. Martin H. Young, Jr.	Director	February 23, 2015

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COBALT INTERNATIONAL ENERGY, INC

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by Securities and Exchange Commission rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States (GAAP). Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

There are inherent limitations to the effectiveness of internal control over financial reporting, however well designed, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that an internal control will be effective under all potential future conditions. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2014. The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

/s/ JOSEPH H. BRYANT	/s/ JOHN P. WILKIRSON
Joseph H. Bryant *Chairman of the Board of Directors and Chief Executive Officer*	John P. Wilkirson *Chief Financial Officer and Executive Vice President*

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Cobalt International Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cobalt International Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2014 consolidated financial statements of Cobalt International Energy, Inc. and our report dated February 23, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2015

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Cobalt International Energy, Inc.

We have audited the accompanying consolidated balance sheets of Cobalt International Energy, Inc. (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cobalt International Energy, Inc. at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cobalt International Energy, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 23, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2015

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Cobalt International Energy, Inc.

Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
	($ in thousands, except per share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 258,721	$ 192,460
Joint interest and other receivables	59,974	124,639
Prepaid expenses and other current assets	14,497	55,857
Inventory	94,674	74,768
Short-term restricted funds	45,062	200,339
Short-term investments	1,530,206	1,319,380
Total current assets	2,003,134	1,967,443
Property, plant, and equipment:		
Oil and gas properties, successful efforts method of accounting, net of accumulated depletion of $0	1,920,979	1,464,383
Other property and equipment, net of accumulated depreciation and amortization of $8,977 and $4,394, as of December 31, 2014 and 2013, respectively	11,382	11,892
Total property, plant, and equipment, net	1,932,361	1,476,275
Long-term restricted funds	105,051	104,496
Long-term investments	326,047	14,661
Deferred income taxes	30,334	17,061
Other assets	53,936	53,737
Total assets	$ 4,450,863	$ 3,633,673
Liabilities and Stockholders' Equity		
Current liabilities:		
Trade and other accounts payable	$ 8,010	$ 131,428
Accrued liabilities	214,972	143,459
Short-term contractual obligations	50,285	49,019
Deferred income taxes	30,334	17,061
Total current liabilities	303,601	340,967
Long-term debt	1,928,528	1,035,980
Long-term contractual obligations	101,945	124,901
Other long-term liabilities	2,523	2,679
Total long-term liabilities	2,032,996	1,163,560
Stockholders' equity:		
Common stock, $0.01 par value per share; 2,000,000,000 shares authorized 408,505,079 and 406,949,839 issued and outstanding as of December 31, 2014 and 2013, respectively	4,085	4,069
Additional paid-in capital	4,137,803	3,641,936
Accumulated deficit during the development stage	(2,027,622)	(1,516,859)
Total stockholders' equity	2,114,266	2,129,146
Total liabilities and stockholders' equity	$ 4,450,863	$ 3,633,673

See accompanying notes.

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Cobalt International Energy, Inc.

Consolidated Statements of Operations

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands except per share data)		
Oil and gas revenue	$ —	$ —	$ —
Operating costs and expenses:			
Seismic and exploration	85,567	74,213	61,583
Dry hole expense and impairment	236,930	351,050	134,085
General and administrative	114,860	105,547	87,963
Depreciation and amortization	4,584	1,874	1,197
Total operating costs and expenses	441,941	532,684	284,828
Operating income (loss)	(441,941)	(532,684)	(284,828)
Other income (expense):			
Gain (loss) on sale of assets	(12)	2,993	—
Interest income	5,958	6,043	5,041
Interest expense	(74,768)	(65,376)	(3,212)
Total other income (expense)	(68,822)	(56,340)	1,829
Net income (loss) before income tax	(510,763)	(589,024)	(282,999)
Income tax expense	—	—	—
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)
Basic and diluted income (loss) per common share	$ (1.25)	$ (1.45)	$ (0.70)
Basic and diluted weighted average common shares outstanding	407,116,144	406,839,997	403,356,174

See accompanying notes.

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Cobalt International Energy, Inc.

Consolidated Statements of Changes in Stockholders' Equity

	Common Stock	Additional Paid-in Capital	Accumulated Deficit During Development Stage	Total
	($ in thousands)			
Balance, December 31, 2011	$ 3,875	$ 2,719,875	$ (644,836)	$ 2,078,914
Common stock issued at public offering, net of costs	181	489,128	—	489,309
Common stock issued for restricted stock and restricted stock units	10	(10)	—	—
Equity based compensation	—	22,410	—	22,410
Exercise of stock options	—	338	—	338
Common stock withheld for taxes on equity based compensation	—	(170)	—	(170)
Conversion option relating to 2.625% convertible senior notes due 2019, net of allocated costs	—	381,416	—	381,416
Net income (loss)	—	—	(282,999)	(282,999)
Balance, December 31, 2012	$ 4,066	$ 3,612,987	$ (927,835)	$ 2,689,218
Common stock issued for restricted stock and stock options	3	(3)	—	—
Equity based compensation	—	28,754	—	28,754
Exercise of stock options	—	198	—	198
Net income (loss)	—	—	(589,024)	(589,024)
Balance, December 31, 2013	$ 4,069	$ 3,641,936	$ (1,516,859)	$ 2,129,146
Common stock issued for restricted stock and stock options	16	(16)	—	—
Equity based compensation	—	31,742	—	31,742
Exercise of stock options	—	33	—	33
Common stock withheld for taxes on equity based compensation	—	(630)	—	(630)
Conversion option relating to 3.125% convertible senior notes due 2024, net of allocated costs	—	464,738	—	464,738
Net income (loss)	—	—	(510,763)	(510,763)
Balance, December 31, 2014	$ 4,085	$ 4,137,803	$ (2,027,622)	$ 2,114,266

See accompanying notes.

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Cobalt International Energy, Inc.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2014	2013	2012
		($ in thousands)	
Cash flows provided from operating activities			
Net income (loss)	$ (510,763)	$ (589,024)	$ (282,999)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation and amortization	4,584	1,874	1,197
Dry hole expense and impairment	236,930	351,050	134,085
Gain on sale of assets	—	(2,993)	—
Equity based compensation	31,742	28,754	22,410
Amortization of premium (accretion of discount) on investments	18,159	21,955	15,091
Amortization of debt discount	71,330	46,847	—
Changes in operating assets and liabilities:			
Joint interest and other receivables	64,679	(62,967)	(1,518)
Inventory	(20,906)	(10,052)	(29,237)
Prepaid expense and other current assets	41,359	(31,915)	(1,726)
Deferred charges	15,980	(32,753)	(10,985)
Trade and other accounts payable	(64,369)	63,552	(3,309)
Accrued liabilities and other	46,749	(696)	16,594
Net cash provided by (used in) operating activities	(64,526)	(216,368)	(140,397)
Cash flows from investing activities			
Capital expenditures for oil and gas properties	(70,639)	(80,439)	(142,841)
Capital expenditures for other property and equipment	(4,074)	(8,483)	(5,139)
Exploration wells drilling in process	(678,017)	(581,194)	(329,534)
Proceeds from sale of oil and gas properties	—	3,006	—
Change in restricted funds	43,667	180,729	29,573
Proceeds from maturity of investment securities	1,700,123	1,366,977	1,082,876
Purchase of investment securities	(2,129,453)	(1,896,591)	(1,199,696)
Net cash provided by (used in) investing activities	(1,138,393)	(1,015,995)	(564,761)
Cash flows from financing activities			
Proceeds from public offering, net of costs	—	—	489,309
Proceeds from debt offering, net of costs	1,269,778	(1,190)	1,348,950
Proceed from exercise of stock options	33	198	338
Payments for common stock withheld for taxes on equity based compensation	(631)	—	(170)
Net cash provided by (used in) financing activities	1,269,180	(992)	1,838,427
Net increase (decrease) in cash and cash equivalents	66,261	(1,233,355)	1,133,269
Cash and cash equivalents, beginning of period	192,460	1,425,815	292,546
Cash and cash equivalents, end of period	$ 258,721	$ 192,460	$ 1,425,815
Cash paid for interest	$ 56,764	$ 34,615	$ —
Non-Cash Disclosures			
Change in accrued capital expenditures	$ (56,129)	$ 58,769	$ (105,802)
Transfer of investment securities to and from restricted funds	$ 112,434	$ 26	$ 178,830

See accompanying notes.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Description of Operations

Cobalt International Energy, Inc. (the "Company") is an independent exploration and production company with operations in the deepwater U.S. Gulf of Mexico and offshore Angola and Gabon in West Africa.

Effective January 1, 2015, Cobalt International Energy, L.P. (the "Partnership"), an indirect wholly-owned subsidiary of the Company, assigned its ownership interest in the oil and gas leases, wells, production facilities and other assets and agreements associated with the Company's Heidelberg development to Cobalt GOM #1 LLC, an indirect wholly-owned subsidiary of the Company.

The terms "Company," "Cobalt," "we," "us," "our," "ours," and similar terms refer to Cobalt International Energy, Inc. unless the context indicates otherwise.

Basis of Presentation

At December 31, 2014, the accompanying consolidated financial statements include the accounts of the Company and the Partnership. Prior to the effective date of a corporate reorganization, both entities were under common control arising from common direct or indirect ownership of each. The transfer of the Partnership interests to the Company represented a reorganization of entities under common control and was accounted for at historical cost.

Recently Issued Accounting Standards

In June 2014, the Financial Accounting Standards Board (the "FASB") amended Accounting Standard Codification Topic No. 915, *Development Stage Entities* (the "ASC Topic 915"), to remove the definition of a development stage entity from the Master Glossary of the ASC, thereby removing the financial reporting distinction between development stage entities and other reporting entities. The amendments eliminate the requirements for development stage entities to (1) present inception-to-date information in the statements of income, cash flows, and shareholder equity, (2) label the financial statements as those of a development stage entity, (3) disclose a description of the development stage activities in which the entity is engaged, and (4) disclose in the first year in which the entity is no longer a development stage entity that in prior years it had been in the development stage.

These amendments and the other remaining disclosure requirements of the ASC Topic 915 should be applied retrospectively. For public business entities, ASC Topic 915 is effective for annual reporting periods beginning after December 15, 2014, and interim periods therein. Early application of ASC Topic 915 is permitted for any annual reporting period or interim period for which the entity's financial statements have not yet been issued or made for issuance. Upon adoption, entities will no longer present or disclose any information required by the ASC Topic 915. The Company elected to apply ASC Topic 915 early effective in the Form 10-Q for the quarter ended June 30, 2014 and other reports thereafter.

Use of Estimates

The preparation of financial statements in conformity with United States generally accepted accounting principles ("GAAP") requires the Company to make estimates and assumptions that affect the reported amounts of assets including proved reserves and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and

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1. Summary of Significant Accounting Policies (Continued)

expenses during the reporting period. Significant estimates the Company makes include (a) accruals related to expenses, (b) assumptions used in estimating fair value of equity based awards and the fair value of the liability component of the convertible senior notes and (c) assumptions used in impairment testing. Although the Company believes these estimates are reasonable, actual results could differ from these estimates.

Fair Value Measurements

The fair values of the Company's cash and cash equivalents, joint interest and other receivables, restricted funds and investments approximate their carrying amounts due to their short-term duration. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. The Company categorizes each of its fair value measurements as applicable to one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. The levels are:

Level 1—Quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities. This category includes the Company's cash and money market funds.

Level 2—Quoted prices in non-active markets or in active markets for similar assets or liabilities, and inputs other than quoted prices that are observable, for the asset or liability, either directly or indirectly for substantially the full contractual term of the asset or liability being measured. This category includes the Company's U.S. Treasury bills, U.S. Treasury notes, U.S. Government agency securities, commercial paper, corporate bonds and certificates of deposits.

Level 3—Inputs that are generally unobservable and typically reflect management's estimate of assumptions that market participants would use in pricing the asset or liability. The Company does not currently have any financial instruments categorized as Level 3.

Revenue Recognition

The Company will follow the "sales" (or cash) method of accounting for oil and gas revenues. Under this method, the Company will recognize revenues on the volumes sold. The volumes sold may be more or less than the volumes to which the Company is entitled based on its ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. For the years ended December 31, 2014, 2013 and 2012, no revenues have been recognized in these consolidated financial statements.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and funds invested in highly liquid instruments with maturities of three months or less from the date of purchase. Demand deposits typically exceed federally insured limits; however, the Company periodically assesses the financial condition of the institutions where these funds are held as well as the credit ratings of the issuers of the highly liquid instruments and believes that the credit risk is minimal.

Restricted Funds

Restricted funds consist of collateral for letters of credit relating to our operations offshore Angola.

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1. Summary of Significant Accounting Policies (Continued)

Investments

The Company's policy on accounting for its investments, which consist entirely of debt securities, is based on the accounting guidance relating to "*Accounting for Certain Investments in Debt and Equity Securities*." The Company considers all highly liquid interest-earning investments with a maturity of three months or less at the date of purchase to be cash equivalents. Investments with original maturities of greater than three months and remaining maturities of less than one year are classified as short-term investments. Investments with maturities beyond one year are classified as long-term investments. The debt securities are carried at amortized costs and classified as held-to-maturity securities as the Company has the positive intent and ability to hold them until they mature. The net carrying value of held-to-maturity securities is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the securities. Held-to-maturity securities are stated at amortized cost, which approximates fair market value as of December 31, 2014 and 2013. Income related to these securities is reported as a component of interest income in the Company's consolidated statement of operations. *See Note 6—Investments.*

Investments are considered to be impaired when a decline in fair value is determined to be other-than-temporary. The Company conducts a regular assessment of its debt securities with unrealized losses to determine whether securities have other-than-temporary impairment ("OTTI"). This assessment considers, among other factors, the nature of the securities, credit rating or financial condition of the issuer, the extent and duration of the unrealized loss, market conditions and whether the Company intends to sell or whether it is more likely than not that the Company will be required to sell the debt securities. As of December 31, 2014 and 2013, the Company has no OTTI in its debt securities.

Capitalized Interest

For exploration and development projects that have not commenced production, interest is capitalized as part of the historical cost of developing and constructing assets. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. *See Note 8—Property, Plant, and Equipment and Note 10—Long-term Debt.*

Joint Interest and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These receivables are usually settled within 30 days of the invoice date.

Property, Plant, and Equipment

The Company uses the "successful efforts" method of accounting for its oil and gas properties. Acquisition costs for unproved leasehold properties and costs of drilling exploration wells are capitalized pending determination of whether proved reserves can be attributed to the areas as a result of drilling those wells. Under the successful efforts method of accounting, proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a units-of-production basis. Successful drilling costs, costs of development and developmental dry holes

1. Summary of Significant Accounting Policies (Continued)

are capitalized and amortized over the proved developed reserves on a units-of-production basis. Significant unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine if an impairment of the cost of individual properties has occurred. Factors taken into account for impairment analysis include results of the technical studies conducted, lease terms and management's future exploration plans. The cost of impairment is charged to expense in the period in which it occurs. Costs incurred for exploration dry holes, geological and geophysical work (including the cost of seismic data), and delay rentals are charged to expense as incurred. Costs of other property and equipment are depreciated on a straight-line basis based on their respective useful lives.

Asset Retirement Obligations

The Company currently does not have any oil and natural gas production or any legal obligations to incur decommissioning costs. Should such production occur in the future, the Company expects to have significant obligations under its lease agreements and federal regulation to remove its equipment and restore land or seabed at the end of oil and natural gas production operations. These asset retirement obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires the Company to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulation often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Pursuant to the accounting guidance relating to "*Asset Retirement Obligations*", the Company is required to record a separate liability for the estimated fair value of its asset retirement obligations, with an offsetting increase to the related oil and natural gas properties representing asset retirement costs on its balance sheet. The cost of the related oil and natural gas asset, including the asset retirement cost, is depreciated over the useful life of the asset. The estimated fair value of asset retirement obligations is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the abandonment liability, the Company will make corresponding adjustments to both the asset retirement obligation and the related oil and natural gas property asset balance. Increases in the discounted abandonment liability and related oil and natural gas assets resulting from the passage of time will be reflected as additional accretion and depreciation expense in the consolidated statements of operations.

Inventory

Inventories consist of various tubular products that are used in the Company's drilling programs. The products are stated at the average cost. Cost is determined using a weighted average method comprised of the purchase price and other directly attributable costs.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

1. Summary of Significant Accounting Policies (Continued)

Income Taxes

The Company applied the liability method of accounting for income taxes in accordance with accounting guidance related to "*Income Taxes*" as clarified by "*Accounting for Uncertainty in Income Taxes*." Under this method, deferred tax assets and liabilities are determined by applying tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Since the Company currently has no production activities and there can be no assurance that the Company will generate any earnings or any specific level of earnings in future years, the Company has established a valuation allowance that equals its net deferred tax assets. *See Note 16.*

Equity-Based Compensation

The Company accounts for stock-based compensation at fair value. The Company grants various types of stock-based awards including stock options, restricted stock and performance-based awards. The fair value of stock option awards is determined using the Black-Scholes-Merton option-pricing model. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, on a straight-line basis for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date. *See Note 14.*

Earnings (Loss) Per Share

Basic income (loss) per share was calculated by dividing net income or loss applicable to common shares by the weighted average number of common shares outstanding during the periods presented. The calculation of diluted income (loss) per share should include the potential dilutive impact of non-vested restricted shares, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, during the period, unless their effect is anti-dilutive. For the year ended December 31, 2014, 5,997,374 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options, the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024, were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2013, 6,735,046 shares of non-vested restricted stock, non-vested restricted stock units, outstanding stock options and the 2.625% convertible senior notes due 2019 were excluded from the diluted income (loss) per share because they are anti-dilutive. For the year ended December 31, 2012, 5,617,697 shares of non-vested restricted stock, non-vested restricted stock units and outstanding stock options were excluded from the diluted income (loss) per share because they are anti-dilutive.

Operating Costs and Expenses

Expenses consist primarily of the costs of acquiring and processing of geological and geophysical data, exploration, and appraisal drilling expenses, consultants, telecommunications, payroll and benefit costs, information system and legal costs, office rent, contract costs, and bookkeeping and audit fees.

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2. Cash and Cash Equivalents

As of December 31, 2014 and 2013, cash and cash equivalents consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cash at banks	$ 57,750	$ 82,428
Money market funds	122,218	75,039
Held-to-maturity securities(1)	78,753	34,993
	$ 258,721	$ 192,460

(1) These securities mature three months or less from date of purchase.

3. Restricted Funds

Restricted funds consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Short-term:		
Collateral on letters of credit for Angola	$ 45,062	$ 200,339
	$ 45,062	$ 200,339
Long-term:		
Collateral on letters of credit for Angola	$ 105,051	$ 104,496
	$ 105,051	$ 104,496
Total restricted funds(1)	$ 150,113	$ 304,835

(1) As of December 31, 2014 and 2013, $150.1 million and $304.8 million, respectively, was held in a collateral account established to secure letters of credit issued in support of the Company's contractually agreed work program obligations on Blocks 9, 20 and 21 offshore Angola. During the year ended December 31, 2014, restricted funds of $155.0 million were released to the Company in connection with completion of a portion of the agreed work program obligations on Block 20 and 21 offshore Angola. As of December 31, 2014, $45.1 million was reclassified from long-term restricted funds to short-term restricted funds in connection with the completion of a portion of the Company's agreed work program obligations on Block 9 and 21 offshore Angola. On February 5, 2015, restricted funds totaling $45.1 million were released to the Company in connection with completion of a portion of the work program obligations on Block 9 and completion of the remaining work program obligations on Block 21. The Block 21 letter of credit was therefore reduced to zero and cancelled effective February 10, 2015. As of December 31, 2014 and 2013, the collateral in this account was invested in U.S. Treasury bills and Treasury notes purchased at discounts and at premiums, respectively, resulting in a net carrying value of $150.1 million and $304.8 million, respectively. The contractual maturities of these securities are within one year.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

4. Joint Interests and Other Receivables

Joint interest and other receivables result primarily from billing shared costs under the respective operating agreements to the Company's partners. These are usually settled within 30 days of the invoice date. As of December 31, 2014 and 2013, the balance in joint interest and other receivables consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Partners in the U.S. Gulf of Mexico	$ 3,274	$ 68,664
Partners in West Africa	46,312	46,897
Accrued interest on investment securities	7,663	5,632
Other	2,725	3,446
	$ 59,974	$ 124,639

5. Prepaid Expenses and Other Current Assets

As of December 31, 2014 and 2013, prepaid expenses and other current assets consisted of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Prepaid expenses:		
Prepaid expenses(1)	$ 6,273	$ 37,796
Other current assets:		
Cash advance to joint venture partner(2)	—	9,685
Rig mobilization, regulatory and other related costs(3)	8,224	8,376
	$ 14,497	$ 55,857

(1) As of December 31, 2014, prepaid expenses include $6.3 million of the prepaid and unamortized portion of payments made for software licenses, related maintenance fees and insurance. As of December 31, 2013, prepaid expenses include $11.5 million of the prepaid and unamortized portion of payments made for software licenses, related maintenance fees, insurance and $26.3 million of prepaid costs associated with the Ensco drilling rig contract. The drilling rig contract terminated in January 2014 and upon receipt and application of prepaid amounts against the final invoice from Ensco, any remaining balance of the prepayment was refunded to the Company.

(2) As of December 31, 2013, the $9.7 million in other current assets relates to payment of cash calls made to our joint interest partner, Total Gabon, for operating costs to drill the Diaman #1B exploration well. This prepayment was applied against the joint interest bills upon receipt from Total Gabon as of December 31, 2014.

(3) As of December 31, 2014 and 2013, the $8.2 million and $8.4 million, respectively, in other current assets relates to the short-term portion of the mobilization and regulatory acceptance testing costs associated with the SSV Catarina drilling rig and the Rowan Reliance drilling rig.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

6. Investments

The Company's investments in held-to-maturity securities which are recorded at amortized cost and approximate fair market value were as follows as of December 31, 2014 and 2013:

	December 31, 2014	December 31, 2013
	($ in thousands)	
U.S. Treasury bills	$ 46,064	$ 304,834
U.S. Treasury notes	104,049	—
Corporate securities	1,321,261	856,002
Commercial paper	483,534	408,033
U.S. Agency securities	24,996	—
Certificates of deposit	105,215	105,000
Total	$ 2,085,119	$ 1,673,869

The Company's consolidated balance sheet included the following held-to-maturity securities:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cash and cash equivalents	$ 78,753	$ 34,993
Short-term investments	1,530,206	1,319,380
Short-term restricted funds	45,062	200,339
Long-term restricted funds	105,051	104,496
Long-term investments	326,047	14,661
	$ 2,085,119	$ 1,673,869

The contractual maturities of these held-to-maturity securities as of December 31, 2014 and 2013 were as follows:

	December 31, 2014		December 31, 2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
	($ in thousands)			
Within 1 year	$ 1,759,072	$ 1,759,072	$ 1,659,208	$ 1,659,208
After 1 year	326,047	326,047	14,661	14,661
	$ 2,085,119	$ 2,085,119	$ 1,673,869	$ 1,673,869

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

7. Fair Value Measurements

The following tables summarize the Company's significant financial instruments as categorized by the fair value measurement hierarchy:

	Level 1		Level 2		
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	Balance as of December 31, 2014
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 57,750	$ 57,750	$ —	$ —	$ 57,750
Money market funds	122,218	122,218			122,218
Commercial paper	—	—	70,524	70,524	70,524
Corporate bonds	—	—	8,229	8,229	8,229
Subtotal	179,968	179,968	78,753	78,753	258,721
Short-term restricted funds:					
U.S. Treasury bills	—	—	45,062	45,062	45,062
Subtotal	—	—	45,062	45,062	45,062
Short-term investments:					
U.S. Agency securities	—	—	24,996	24,996	24,996
Corporate bonds	—	—	986,985	986,985	986,985
Commercial paper	—	—	413,010	413,010	413,010
Certificates of deposits	—	—	105,215	105,215	105,215
Subtotal	—	—	1,530,206	1,530,206	1,530,206
Long-term restricted funds:					
U.S. Treasury bills	—	—	1,002	1,002	1,002
U.S. Treasury notes	—	—	104,049	104,049	104,049
Subtotal	—	—	105,051	105,051	105,051
Long-term investments:					
Corporate bonds	—	—	326,047	326,047	326,047
Subtotal	—	—	326,047	326,047	326,047
Total	$ 179,968	$ 179,968	$ 2,085,119	$ 2,085,119	$ 2,265,087

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

7. Fair Value Measurements (Continued)

	Level 1		Level 2		
	Carrying Value	Fair Value(1)	Carrying Value	Fair Value(1)	Balance as of December 31, 2013
			($ in thousands)		
Cash and cash equivalents:					
Cash	$ 82,428	$ 82,428	$ —	$ —	$ 82,428
Money market funds	75,039	75,039	—	—	75,039
Commercial paper	—	—	9,993	9,993	9,993
Certificate of deposits	—	—	25,000	25,000	25,000
Subtotal	&sbsp; 157,467	157,467	34,993	34,993	192,460
Short-term restricted funds:					
U.S. Treasury notes	—	—	200,339	200,339	200,339
Subtotal	—	—	200,339	200,339	200,339
Short-term investments:					
Corporate bonds	—	—	848,307	848,307	848,307
Commercial paper	—	—	391,073	391,073	391,073
Certificates of deposits	—	—	80,000	80,000	80,000
Subtotal	—	—	1,319,380	1,319,380	1,319,380
Long-term restricted funds:					
U.S. Treasury notes	—	—	104,496	104,496	104,496
Subtotal	—	—	104,496	104,496	104,496
Long-term investments:					
Commercial paper	—	—	6,967	6,967	6,967
Corporate bonds	—	—	7,694	7,694	7,694
Subtotal	—	—	14,661	14,661	14,661
Total	$ 157,467	$ 157,467	$ 1,673,869	$ 1,673,869	$ 1,831,336

(1) As of December 31, 2014 and 2013, the Company did not record any OTTI on these assets.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

8. Property, Plant, and Equipment

Property, plant, and equipment is stated at cost less accumulated depreciation/amortization and consisted of the following:

	Estimated Useful Life (Years)	December 31, 2014	December 31, 2013
		($ in thousands)	
Oil and Gas Properties:			
Proved properties:			
Well and development costs		$ 183,221	$ 92,579
Total proved properties		183,221	92,579
Unproved properties:			
Oil and gas leasehold		762,518	754,894
Less: accumulated valuation allowance		(211,224)	(160,913)
		551,294	593,981
Exploration wells in process		1,186,464	777,823
Total unproved properties		1,737,758	1,371,804
Total oil and gas properties, net		1,920,979	1,464,383
Other Property and Equipment:			
Computer equipment and software	3	5,672	5,115
Office equipment and furniture	3 - 5	2,139	2,132
Vehicles	3	265	265
Leasehold improvements	3 - 10	2,488	2,456
Running tools and equipment	3	9,795	6,318
		20,359	16,286
Less: accumulated depreciation and amortization		(8,977)	(4,394)
Total other property and equipment, net		11,382	11,892
Property, plant, and equipment, net		$ 1,932,361	$ 1,476,275

The Company recorded $4.6 million, $1.9 million, and $1.2 million of depreciation and amortization expense for the years ended December 31, 2014, 2013 and 2012, respectively.

Proved Oil and Gas Properties

The Heidelberg project was formally sanctioned for development in mid-2013. As a result of the project sanction, the Company reclassified its Heidelberg exploration well costs to proved property well and development costs and these costs will be amortized when the related proved developed reserves are produced. As of December 31, 2014, the well and development costs consist of $51.1 million relating to exploration well costs for the Heidelberg #1 exploration well, Heidelberg #3 appraisal well, Heidelberg #4 and Heidelberg #6 development wells and $132.1 million for costs associated with field development. As of December 31, 2013, the well and development costs consist of $31.6 million

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8. Property, Plant, and Equipment (Continued)

relating to exploration well costs for the Heidelberg #1 exploration well and Heidelberg #3 appraisal well and $61.0 million for costs associated with field development.

Unproved Oil and Gas Properties

As of December 31, 2014 and 2013, the Company has the following unproved property acquisition costs, net of valuation allowance on the consolidated balance sheets:

	December 31, 2014	December 31, 2013
	($ in thousands)	
U.S. Gulf of Mexico:		
Individual oil and gas leaseholds with carrying value greater than $1 million	$ 320,731	$ 328,128
Individual oil and gas leaseholds with carrying value less than $1 million	83,916	68,895
	404,647	397,023
Accumulated valuation allowance & impairment	(208,724)	(160,913)
	195,923	236,110
West Africa:		
Blocks 9, 20 and 21 offshore Angola	355,876	355,876
Diaba Block offshore Gabon	1,995	1,995
	357,871	357,871
Accumulated impairment	(2,500)	—
	355,371	357,871
Total oil and gas leasehold	$ 551,294	$ 593,981

As of December 31, 2014 and 2013, the Company has $353.4 million and $355.9 million, respectively, of unproved property acquisition costs, net of valuation allowance for impairment, relating to its 40% working interest each in Blocks 9, 20 and 21 offshore Angola and $2.0 million of unproved property acquisition costs relating to its 21.25% working interest in the Diaba Block, offshore Gabon. On December 20, 2011, the Company acquired a 40% working interest in Block 20 offshore Angola for a consideration of $347.1 million, of which $337.1 million is contractually scheduled to be paid over five years commencing in January 2012. As of December 31, 2014, the remaining unpaid balance of $128.6 million was accrued in short-term and long-term contractual obligations. *See Note 11—Contractual Obligations.*

As of December 31, 2014 and 2013, the Company also has $195.9 million and $236.1 million, respectively, net of valuation allowance for impairment, of unproved property acquisition costs relating to its U.S. Gulf of Mexico properties. In June and July of 2014, the Company paid a total consideration of $27.8 million for the acquisition of ownership interests in unproved oil and gas properties in the deepwater U.S. Gulf of Mexico. On February 26, 2013, the Company executed a Purchase and Sale agreement (the "PSA") to sell its ownership interests on an unproved oil and gas property on Mississippi Canyon Block 209 for a total consideration of $5.6 million. The Company received $1.5 million at closing and an additional $1.5 million in September 2013 when the buyer commenced

8. Property, Plant, and Equipment (Continued)

operations on the property. Pursuant to the terms and conditions of the PSA, the Company will receive the remaining $2.6 million contingent upon the purchaser's commencement of production on this property in the future. For the year ended December 31, 2013, the Company recognized a gain of $3.0 million on the sale of assets as a result of this transaction. During the year ended December 31, 2013, the Company paid a total consideration of $37.6 million for the acquisition of ownership interests in unproved oil and gas properties on Garden Banks Block 822, Mississippi Canyon Block 605 and Walker Ridge Block 232 in the deepwater U.S. Gulf of Mexico.

As of December 31, 2014 and 2013, the Company has a net total of $551.3 million and $594.0 million, respectively, of unproved property acquisition costs on the consolidated balance sheets.

Acquisition costs of unproved properties are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent associated with successful exploration activities. There are no impairment indicators to date that would require the Company to impair the unproved properties in Blocks 20 and 21 offshore Angola and in the Diaba Block offshore Gabon. For the unproved properties associated with Block 9 offshore Angola, the Company recorded an impairment allowance of $2.5 million on its 40% ownership interest on Block 9 since the Company has no plan to extend its exploration obligations under the Risk Services Agreement for Block 9. Oil and gas leases for unproved properties in the U.S. Gulf of Mexico with a carrying value greater than $1.0 million are assessed individually for impairment based on the Company's current exploration plans and an allowance for impairment is provided if impairment is indicated. Leases that are individually less than $1.0 million in carrying value or are near expiration are amortized on a group basis over the average terms of the leases at rates that provide for full amortization of leases upon lease expiration. These leases have expiration dates ranging from 2015 through 2024. As of December 31, 2014 and 2013, the balance for unproved properties that were subject to amortization before impairment provision was $83.7 million and $68.9 million, respectively. The Company recorded a lease impairment allowance of $70.5 million, $87.0 million and $60.2 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Capitalized Exploration Well Costs

If an exploration well provides evidence as to the existence of sufficient quantities of hydrocarbons to justify evaluation for potential development, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally, deepwater and international locations) depending upon, among other things, (i) the amount of hydrocarbons discovered, (ii) the outcome of planned geological and engineering studies, (iii) the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan and (iv) the requirement for government sanctioning in international locations before proceeding with development activities. The

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

8. Property, Plant, and Equipment (Continued)

following tables reflect the Company's net changes in and the cumulative costs of capitalized exploration well costs (excluding any related leasehold costs):

	December 31, 2014	December 31, 2013	December 31, 2012
		($ in thousands)	
Beginning of period	$ 777,823	$ 451,024	$ 178,338
Additions to capitalized exploration			
U.S. Gulf of Mexico:			
Exploration well costs	143,431	154,877	178,295
Capitalized interest	6,965	3,928	—
West Africa:			
Exploration well costs	379,461	457,608	168,309
Capitalized interest	44,243	12,271	—
Reclassifications to wells, facilities, and equipment based on determination of proved reserves	—	(38,446)	—
Amounts charged to expense(1)	(165,459)	(263,439)	(73,918)
End of period	$ 1,186,464	$ 777,823	$ 451,024

(1) The amount of $165.5 million for the year ended December 31, 2014 represents $64.3 million of impairment charges on exploration wells drilled in the U.S. Gulf of Mexico and $101.2 million of impairment charges on exploration wells drilled offshore Angola, all of which did not encounter commercial hydrocarbons. The amount of $263.4 million for the year ended December 31, 2013 represents $120.0 million of impairment charges on exploration wells drilled in the U.S. Gulf of Mexico which did not encounter commercial hydrocarbons, $126.3 million of impairment charges on exploration wells drilled offshore Angola which failed to flow measurable hydrocarbons from drill stem tests and a portion of the cost of exploration wells drilled offshore Angola that were determined to have no utility in the lowest interval beneath the pay zone and $17.1 million of impairment charges on the exploration well drilled offshore Gabon which needed to be re-spud due to mechanical problems with the wellbore.

	December 31, 2014	December 31, 2013
	($ in thousands)	
Cumulative costs:		
U.S. Gulf of Mexico		
Exploration well costs	$ 283,885	$ 204,707
Capitalized interest	10,894	3,928
West Africa		
Exploration well costs	835,171	556,917
Capitalized interest	56,514	12,271
	$ 1,186,464	$ 777,823

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

8. Property, Plant, and Equipment (Continued)

Well costs capitalized for a period greater than one year after completion of drilling (included in the table above) are summarized as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
U.S. Gulf of Mexico	$ 208,634	$ 186,510	$ 89.490
West Africa	566,745	213,265	105,363
	$ 775,379	$ 399,775	$ 194,853
Number of projects with exploration well costs that have been capitalized more than a year	8	3	3

The above capitalized exploration well costs suspended over a year are pending ongoing evaluation including, but not limited to, results of additional appraisal drilling, well-test analysis, additional geological and geophysical data and approval of a development plan. Management believes these discoveries exhibit sufficient indications of hydrocarbons to justify potential development and is actively pursuing efforts to fully assess them. If additional information becomes available that raises substantial doubt as to the economic or operational viability of these discoveries, the associated costs will be expensed at that time.

9. Other Assets

As of December 31, 2014 and 2013, the balance in other assets consisted of the following:

	December 31,	
	2014	2013
	($ in thousands)	
Debt issue cost(1)	$ 36,708	$ 20,983
Long-term portion of prepaid shorebase leases	2,244	3,241
Rig mobilization costs(2)	14,984	11,153
Long-term accounts receivable(3)	—	17,923
Other	—	437
	$ 53,936	$ 53,737

(1) As of December 31, 2014, the $36.7 million in debt issue costs included $18.5 million and $18.2 million in costs related to the issuance of the Company's 2.625% convertible senior notes due 2019 and the Company's 3.125% convertible senior notes due 2024, respectively, as described in *Note 10—Long-term Debt*. As of December 31, 2013, the $21.0 million in debt issue costs was related to the issuance of the Company's 2.625% convertible senior notes due 2019 as described in *Note 10—Long-term Debt*. These debt issue costs are amortized over the life of the notes using the effective interest method.

(2) As of December 31, 2014 and 2013, the $15.0 million and $11.2 million, respectively, relate to costs associated with the long-term mobilization and the regulatory acceptance testing of the SSV Catarina drilling rig which is currently drilling in West Africa, and

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

9. Other Assets (Continued)

costs relating to the Rowan Reliance drilling rig which was delivered in January 2015 and is currently drilling our North Platte #2 appraisal well. These costs are or will be amortized over the term of the drilling rig contracts.

(3) As of December 31, 2013, the $17.9 million of long-term accounts receivable was related to a 3.75% cost interest disputed by one of our former partners on Block 9 and 21 offshore Angola. On October 30, 2014, the Company collected the entire balance due from the Company's partner on Block 9 and 21.

10. Long-term Debt

As of December 31, 2014, the Company's long-term debt consists of the 2.625% convertible senior notes due 2019 issued on December 17, 2012 (the "2.625% Notes") and the 3.125% convertible senior notes due 2024 issued on May 13, 2014 (the "3.125% Notes", and, collectively with the 2.625% Notes, the "Notes") as follows:

2.625% Convertible Senior Notes due 2019

On December 17, 2012, the Company issued $1.38 billion aggregate principal amount of the 2.625% Notes. The 2.625% Notes are the Company's senior unsecured obligations and interest is payable semi-annually in arrears on June 1 and December 1 of each year. The 2.625% Notes will mature on December 1, 2019, unless earlier repurchased or converted in accordance with the terms of the 2.625% Notes. The 2.625% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the maturity date, in multiples of $1,000 principal amount. The 2.625% Notes are convertible at an initial conversion rate of 28.023 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $35.68 per share for a total of approximately 38.7 million underlying shares. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 2.625% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

3.125% Convertible Senior Notes due 2024

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of the 3.125% Notes. The 3.125% Notes are the Company's senior unsecured obligations and rank equal in right of payment to the 2.625% Notes. Interest on the 3.125% Notes is payable semi-annually in arrears on May 15 and November 15 of each year. The 3.125% Notes will mature on May 15, 2024, unless earlier repurchased, converted or redeemed in accordance with the terms of the Notes. Prior to November 15, 2023, the 3.125% Notes are convertible only under the following circumstances: (1) during any fiscal quarter commencing after September 30, 2014 (and only during such fiscal quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during a 30 consecutive trading-day period ending on, and including, the last trading day of the immediately preceding fiscal quarter exceeds $30.00 on each applicable trading day; (2) during the five business-day period after any five consecutive trading-day period (the "3.125% Notes Measurement Period") in which the trading price per $1,000 principal amount of notes for each trading day of the

Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

10. Long-term Debt (Continued)

3.125% Notes Measurement Period was less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; (3) if the Company calls all or any portion of the 3.125% Notes for redemption, at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the related redemption date; or (4) upon the occurrence of specified distributions or the occurrence of specified corporate events. On or after November 15, 2023, the 3.125% Notes may be converted at the option of the holder at any time prior to 5:00 p.m., New York City time, on the second scheduled trading day immediately preceding the stated maturity date, in multiples of $1,000 principal amount. As of December 31, 2014 and 2013, none of the conditions allowing holders of the 3.125% Notes to convert had been met.

The 3.125% Notes are convertible at an initial conversion rate of 43.3604 shares of common stock per $1,000 principal amount, representing an initial conversion price of approximately $23.06 per share for a total of approximately 56.4 million underlying shares. The conversion rate is subject to adjustment upon the occurrence of certain events, as defined in the indenture governing the 3.125% Notes, but will not be adjusted for any accrued and unpaid interest except in limited circumstances. Upon conversion, the Company's conversion obligation may be satisfied, at the Company's option, in cash, shares of common stock or a combination of cash and shares of common stock.

Holders of the Notes who convert their Notes in connection with a "make- whole fundamental change", as defined in the indenture governing these Notes, may be entitled to a make-whole premium in the form of an increase in the conversion rate. Additionally, in the event of a fundamental change, as defined in the indenture governing the Notes, holders of the Notes may require the Company to repurchase for cash all or a portion of their Notes equal to $1,000 or a multiple of $1,000 at a fundamental change repurchase price equal to 100% of the principal amount of Notes, plus accrued and unpaid interest, if any, to, but not including, the fundamental change repurchase date.

Upon the occurrence of an Event of Default, as defined within the indenture governing the Notes, the trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding may declare 100% of the principal of, and accrued and unpaid interest on, all the Notes to be due and payable immediately.

In accordance with accounting guidance relating to, "*Debt with Conversion and Other Options*", the Company separately accounts for the liability and equity conversion components of the Notes due to the Company's option to settle the conversion obligation in cash. The fair value of the Notes excluding the conversion feature at the date of issuance was calculated based on the fair value of similar non-convertible debt instruments. The resulting value of the conversion option of the Notes was recognized as a debt discount and recorded as additional paid-in capital on the Company's consolidated balance sheets. Total debt issue cost on the Notes was allocated to the liability component and to the equity component of the Notes accordingly. The debt discount and the liability component of the debt issue costs are amortized over the term of the Notes. The effective interest rate used to amortize the debt discount and the liability component of the debt issue costs were approximately 8.40% and 8.97% on the 2.625% Notes and the 3.125% Notes, respectively, based on the Company's estimated non-convertible borrowing rate as of the date the Notes were issued. Since the Company incurred losses for all periods, the impact of the conversion option would be anti-dilutive to the earnings per share and therefore was not included in the calculation.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

10. Long-term Debt (Continued)

The carrying amounts of the liability components of the Notes were as follows:

	December 31, 2014			December 31, 2013		
	Principal Amount	Unamortized discount(1)	Carrying Amount	Principal Amount	Unamortized discount	Carrying Amount
	($ in thousands)					
Carrying amount of liability component						
2.625% Notes	$ 1,380,000	$ (295,509)	$ 1,084,491	$ 1,380,000	$ (344,020)	$ 1,035,980
3.125% Notes	1,300,000	(455,963)	844,037	—	—	—
Total	$ 2,680,000	$ (751,472)	$ 1,928,528	$ 1,380,000	$ (344,020)	$ 1,035,980

(1) Unamortized discount will be amortized over the remaining life of the Notes which is 5 years for the 2.625% Notes and 9.50 years for the 3.125% Notes.

The carrying amounts of the equity components of the Notes were as follows:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Debt discount relating to value of conversion option	$ 866,340	$ 390,540
Debt issue costs	(20,185)	(9,124)
Total	$ 846,155	$ 381,416

Fair Value The fair value of the Notes excluding the conversion feature was calculated based on the fair value of similar non-convertible debt instruments since an observable quoted price of the Notes or a similar asset or liability is not readily available. As of December 31 2014 and 2013, the fair values of the Notes were as follows:

	December 31, 2014	December 31, 2013
	($ in thousands)	
2.625% Notes	$ 1,361,000	$ 1,227,000
3.125% Notes	1,047,000	—
Total	$ 2,408,000	$ 1,227,000

As of December 31, 2014, the Company had $8.0 million in accrued interests on the Notes.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

10. Long-term Debt (Continued)

Interest expense associated with the 2.625% convertible senior notes due 2019 and the 3.125% convertible senior notes due 2024 was as follows:

	For Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Interest expense associated with accrued interest(1)	$ 3,271	$ 18,529	$ 1,294
Interest expense associated with accretion of debt discount	68,348	44,789	1,843
Interest expense associated with amortization of debt issue costs	3,149	2,058	75
	$ 74,768	$ 65,376	$ 3,212

(1) The $3.3 million, $18.5 million and $1.3 million for the years ended December 31, 2014, 2013 and 2012, respectively, represent interest expense net of capitalized amounts of $58.5 million, $17.7 million and $0 million, respectively.

As of December 31, 2014, and December 31, 2013, the debt discounts associated with our convertible senior notes resulted in the recognition of $264.3 million and $121.0 million of deferred tax liability, respectively. The Company is in an overall net deferred tax assets position with a full valuation allowance. Therefore, the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

11. Contractual Obligations

The short-term and long-term contractual obligations consist of the following:

	December 31, 2014	December 31, 2013
	($ in thousands)	
Short-term Contractual Obligations:		
Social obligation payments for Block 9, offshore Angola	$ 560	$ 150
Social obligation payments for Block 21, offshore Angola	1,156	300
Social obligation and bonus payments for Block 20, offshore Angola(1)	48,569	48,569
	$ 50,285	$ 49,019
Long-term Contractual Obligations:		
Social and work program obligation payments for Block 9, offshore Angola	$ 21,875	$ 669
Social obligation payments for Block 21, offshore Angola	74	1,381
Social obligation and bonus payments for Block 20, offshore Angola(1)	79,996	122,851
	$ 101,945	$ 124,901

(1) The total amount of $128.6 million under social obligation payments for Block 20 has been capitalized in unproved oil and gas leasehold. *See Note 8—Property, Plants and Equipment.*

12. Stockholders' Equity

On January 15, 2012, the Company withheld the issuance of an aggregate amount of 9,127 shares of its common stock, at a price of $18.74 per share, to satisfy tax withholding obligations of certain of its officers that arose upon the distribution of deferred stock compensation.

On February 29, 2012, the Company issued 18,050,000 shares of common stock at a public offering price of $28.00 per share.

On December 17, 2012, the Company issued $1.38 billion aggregate principal amount of its 2.625% convertible senior notes due 2019. As of December 31, 2013 and 2012, $381.4 million was recorded as the equity component of the 2.625% Notes. *See also Note 10—Long-term Debt.*

On May 13, 2014, the Company issued $1.3 billion aggregate principal amount of its 3.125% convertible senior notes due on 2024. As of December 31, 2014, $464.7 million was recorded as the equity component of the 3.125% Notes. *See also Note 10—Long-term Debt.*

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13. Seismic and Exploration Expenses

Seismic and exploration expenses consisted of the following:

	For Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Seismic costs	$ 34,359	$ 63,721	$ 42,447
Leasehold delay rentals	7,391	6,660	6,383
Drilling rig expense and other exploration expense	43,817	3,832	12,753
	$ 85,567	$ 74,213	$ 61,583

14. Equity based Compensation

Overview. Under the Company's Long Term Incentive Plan (the "Incentive Plan"), the Company may issue stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock-based awards to employees. At December 31, 2014, 4,043,263 shares remain available for grant under the Incentive Plan. However, on January 15, 2015 the Company granted a total of 379,746 shares of restricted stock and 746,268 stock options to three senior officers as required pursuant to their employment agreements. In addition, on February 19, 2015, the Company awarded 2,757,982 shares of restricted stock and 1,526,835 stock appreciation rights to employees as part of the Company's annual long-term equity incentive program. These awards combined with first quarter new hire and termination activity representing a net new issuance of 26,853 shares has resulted in 132,414 shares remaining available for issuance under the Incentive Plan as of February 19, 2015.

On January 28, 2010, the Company adopted the Non-Employee Directors Compensation Plan (the "NED Plan"). Under the NED Plan, the Company may issue options, restricted stock units, other stock-based award or retainers to non-employee directors. At December 31, 2014, 415,682 shares remain available for grant under the NED Plan.

In accordance with ASC No. 718, *Compensation—Stock Compensation,* the Company recognizes compensation cost for equity-based compensation to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant, net of estimated forfeitures. If actual forfeitures differ from the Company's estimates, additional adjustments to compensation expense will be required in future periods.

Restricted Stock. The Company accounted for the restricted stock based on ASC Topic 718 as described above. For restricted stock awards with market conditions, the fair value of the awards is measured using the asset-or-nothing option pricing model. Restricted stock awards without market conditions and the performance-based awards are valued using the market price of the Company's common stock on the grant date. The Company records compensation cost, net of estimated forfeitures, for stock-based compensation awards over the requisite service period except for performance-based awards. For performance-based awards, compensation cost is recognized over the requisite service period as and when the Company determines that the achievement of the performance condition is probable, using the per-share fair value measured at grant date.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

14. Equity based Compensation (Continued)

The following table summarizes the information about the restricted stock awarded to employees for years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,					
	2014		2013		2012	
	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share	Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested shares at beginning of year	4,334,886	$ 14.31	4,040,825	$ 13.05	4,599,783	$ 11.27
Granted	2,275,317	$ 14.53	620,840	$ 24.58	487,710	$ 26.01
Vested	(1,433,172)	$ 16.32	(239,317)	$ 17.37	(738,628)	$ 13.05
Forfeited or expired(1)	(2,374,242)	$ 10.63	(87,462)	$ 20.91	(308,040)	$ 12.17
Non-vested shares at end of year	2,802,789	$ 16.44	4,334,886	$ 14.31	4,040,825	$ 13.05
Weighted-average vesting period remaining	3.08 years		1.22 years		1.87 years	
Unrecognized compensation ($ in thousands)	$ 34,066		$ 22,467		$ 23,827	

(1) The 2,374,242 forfeited or expired restricted shares for the year ended December 31, 2014 include 2,306,173 restricted shares that were forfeited on December 21, 2014 because the market condition attached to the vesting terms of the awards was not met.

A total of 58,038 restricted stock units were granted to non-employee directors during the year ended December 31, 2014. As of December 31, 2014, the Company has granted a cumulative total of 235,801 restricted stock units to non-employee directors. For the years ended December 31, 2014, 2013 and 2012, the Company also granted 26,438, 15,318 and 12,221 shares of common stock, respectively, for annual retainers to non-employee directors who elected to be compensated by stock in lieu of cash payments. For the years ended December 31, 2014, 2013 and 2012, the weighted average fair values of these shares at grant date were $17.52, $25.40 and $21.35 per share, respectively.

Non-Qualified Stock Options. The Company grants non-qualified stock options to employees at an exercise price equal to the market value of the Company's common stock on the grant date. The non-qualified stock option awards have contractual terms of 10 years. The options granted in February 2014 and 2013 will vest 50% at the end of the third year from date of grant and 50% at the end of the fourth year from date of grant. The options granted in 2012 were fully vested during the year ended December 31, 2014.

The fair value of each stock option granted is determined using the Black-Scholes-Merton option-pricing model based on several assumptions. These assumptions are based on management's best

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14. Equity based Compensation (Continued)

estimate at the time of grant. The Company used the following the weighted average of each assumption based on the grants in 2014:

	2014
Expected Term in Years	5.5
Expected Volatility	57.27%
Expected Dividends	—%
Risk-Free Interest Rate	1.69%

The Company estimates expected volatility based on an analysis of its stock price since the IPO and comparing the stock price volatility for the period from IPO date through December 31, 2014 with the historical stock price volatility of a similar exploration and production company. The Company estimates the expected term of its option awards based on the vesting period and average remaining contractual term, referred to as the "simplified method". The Company uses this method to provide a reasonable basis for estimating its expected term based on a lack of sufficient historical employee exercise data on stock option awards.

A summary of the stock options activities for the year ended December 31, 2014 is presented below:

	Shares	Weighted Average Exercise Price	Weighted-Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (thousands)
Outstanding at January 1, 2014	2,338,718	$ 20.24	8.0	$ —
Granted	812,055	$ 17.50		
Exercised	(3,005)	$ 12.45		$ 17,837
Forfeited or expired	(11,221)	$ 24.02		
Outstanding at December 31, 2014	3,136,547	$ 19.52	7.57	$ —
Vested or expected to vest at December 31, 2014	1,693,193	$ 20.82	8.61	$ —
Exercisable at December 31, 2014	1,411,271	$ 17.93	6.30	$ —

The weighted-average grant-date fair value of stock options granted during 2014 and 2013 was $9.12 and $14.08 per option, respectively, using the Black-Scholes option-pricing model. As of December 31, 2014, $12.2 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 2.46 years.

Restricted Stock Units. On December 3, 2010, the Company granted 198,838 restricted stock units to employees pursuant to a Restricted Stock Unit (RSU) Award Agreement. Under the RSU Award Agreement the share-based payment was earned based on the number of successful wells drilled during the three year period ending December 31, 2013. The RSU award vested within a range of 0% to 200% of the number of RSU shares awarded on scheduled vesting dates contingent upon the recipient's continued service at each vesting date and based on the achievement of successful wells drilled as defined in the RSU Award Agreement. The recipients could not vest in an amount greater than 200% of the Award or in aggregate 397,676 RSU shares. The percentage of the RSU awards vested at each of the three year periods ending December 31, 2013 was calculated by the number of

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

14. Equity based Compensation (Continued)

successful wells drilled during the respective years multiplied by vesting percentages ranging from 25% to 37.5%. As of December 31, 2014, the RSU shares were fully vested.

A summary of the restricted stock units activities for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Year Ended December 31,								
	2014			2013			2012		
	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit	Number of shares relating Restricted Stock Units		Weighted Average Grant Date Fair Value Per Unit
Non-vested at beginning of year	21,624	$	30.50	109,275	$	30.50	198,838	$	12.45
Granted	—		—	—		—	—		—
Vested	(21,624)	$	30.50	(87,401)	$	30.50	(74,537)	$	30.50
Forfeited or expired	—		—	(250)	$	30.50	(15,026)	$	30.50
Non-vested at end of year	—		—	21,624	$	30.50	109,275	$	30.50
Weighted-average period remaining	—			—			1 year		

The table below summarizes the equity-based compensation costs recognized for years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Restricted stock:			
Employees	$ 20,971	$ 15,470	$ 13,378
Non-employee directors	1,476	1,260	970
Stock options:			
Employees	9,295	7,405	3,790
Restricted stock units (performance-based)	—	4,619	4,272
	$ 31,742	$ 28,754	$ 22,410

15. Employee Benefit Plan

In 2006, the Company established the Cobalt International Energy, L.P., defined contribution 401(k) plan (the Plan). All employees of the Company after three months of continuous employment are eligible to participate in the Plan. The plan is discretionary and provides a 6% employee contribution match as determined by the Company's Board of Directors. Effective December 31, 2009, the Plan was amended to discontinue the employer's matching contributions. Effective January 1, 2012, the Company reinstituted the 6% employee contribution match. For the years ended December 31, 2014, 2013 and 2012, the Company recorded $1.0 million, $0.8 million, and $0.5 million, respectively, in benefits contributions to the Plan, which are included in general and administrative expenses.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

16. Income Taxes

For the years ended December 31, 2014, 2013 and 2012, the Company recorded a net deferred tax asset of $568.0 million, $461.6 million, and $269.6 million, respectively with a corresponding full valuation allowance of $568.0 million, $461.6 million, and $269.6 million, respectively, for the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

The components of the income tax provision (benefit) are as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
Current taxes:			
U.S. federal	$ —	$ —	$ —
Foreign	—	—	—
Deferred taxes:			
U.S. federal	—	—	—
Foreign	—	—	—
Total	$ —	$ —	$ —

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) for years ended December 31, 2014, 2013 and 2012 are as follows:

	Year Ended December 31,		
	2014	2013	2012
	($ in thousands)		
U.S.:			
Net income (loss) as reported	$ (307,025)	$ (387,210)	$ (229,372)
Less: net income (loss) applicable to period before corporate reorganization	—	—	—
Foreign:			
Net income (loss) as reported	(203,738)	(201,814)	(53,627)
Less: net income (loss) applicable to period before corporate reorganization	—	—	—
Net income (loss) applicable to period after corporate reorganization	$ (510,763)	$ (589,024)	$ (282,999)

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

16. Income Taxes (Continued)

	Year Ended December 31,					
	2014		2013		2012	
	($ in thousands)					
Income tax expense (benefit) at the federal statutory rate	$ (178,767)	35.0%	$ (206,159)	35.0%	$ (99,050)	35.0%
State income taxes, net of federal income tax benefit	(828)	0.2%	(489)	0.1%	(512)	0.2%
Foreign income tax	(111,151)	21.8%	(70,994) &sbsp;	12.1%	4,447	–1.6%
Other	9,098	–1.8%	366	–0.1%	2,678	–0.9%
Valuation allowance(1)	281,648	–55.2%	277,276	–47.1%	92,437	–32.7%
	$ —	—%	$ &5151;	—%	$ —	—%

(1) The change in the deferred tax asset valuation allowance of $277.3 million for the year end December 31, 2013, excludes a $85.3 million net decrease in valuation allowance due to previously unrecorded foreign deferred tax assets and a deferred tax liability related to the Company's convertible debt instrument that did not impact the rate reconciliation.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

16. Income Taxes (Continued)

purposes. The significant components of the Company's deferred tax assets and liabilities were as follows:

		As of December 31,	
		2014	2013
		($ in thousands)	
Short-term deferred tax liabilities:			
2.625% convertible senior notes due 2019(1)	&sbsp;	$ 18,479	$ 17,061
3.125% convertible senior notes due 2024(1)		11,855	—
Total short-term deferred tax liabilities		30,334	17,061
Long-term deferred tax liabilities:			
2.625% convertible senior notes due 2019		$ 85,471	$ 103,951
3.125% convertible senior notes due 2024		148,507	—
Oil and gas properties		54,461	22,135
Total long-term deferred tax liabilities		288,439	126,086
Long-term deferred tax assets:			
Seismic and exploration costs		457,854	280,095
Stock based compensation		18,092	20,842
Domestic NOL carry forwards		415,608	273,163
Foreign NOL carry forwards		38,200	28,633
Other		(43,021)	1,976
Valuation allowance		(567,960)	(461,562)
Total long-term deferred assets		318,773	143,147
Net long-term deferred assets		30,334	17,061
Net deferred tax assets		$ —	$ —

(1) The recognition of the liability and equity components of the debt resulted in a taxable temporary basis difference and recorded as an adjustment to additional paid-in capital.

The Company has established a full valuation allowance against the deferred tax assets where the Company has determined that it is more likely than not that all of the deferred tax assets will not be realized. Because of the full valuation allowance, no income tax expense or benefit is reflected on the consolidated statement of operations for years ended December 31, 2014, 2013 and 2012.

The NOL carryforward for federal and state income tax purposes of approximately $1.2 billion and $65.2 million as of December 31, 2014 begins to expire in 2025 and 2024, respectively. The utilization of the NOL carryforwards is dependent upon generating sufficient future taxable income in the appropriate jurisdictions within the carryforward period.

As of December 31, 2014, the Company had NOL carryforward for foreign income tax purposes of approximately $73.8 million which begins to expire in 2014. The Company has determined that it is more likely than not, that the foreign NOLs will not be fully realized. Therefore, a full valuation allowance was established for these net deferred tax assets.

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16. Income Taxes (Continued)

There were no unrecognized tax benefits or accrued interest or penalties associated with unrecognized tax benefits as of December 31, 2014 and 2013.

17. Commitments

The following table summarizes by period the payments due for the Company's estimated commitments, excluding long-term debt, as of December 31, 2014:

	Payments Due By Year					
	2015	2016	2017	2018	2019	Thereafter
	($ in thousands)					
Drilling Rig and Related Contracts	$ 544,559	$ 299,702	$ 208,104	$ 17,104	$ —	$ —
Operating Leases	9,755	4,801	2,309	2,369	2,405	5,626
Lease Rentals(1)	7,353	5,460	5,007	2,282	1,973	7,223
Social and Work Program Payment Obligations(2)	55,999	84,729	5,714	5,714	—	—
Total	**$ 617,666**	**$ 394,692**	**$ 221,134**	**$ 27,469**	**$ 4,378**	**$ 12,849**

(1) Relates to the annual delay rental payments payable to the Office of Natural Resources Revenue within the U.S. Department of the Interior with respect to the Company's U.S. Gulf of Mexico leases. These annual payments are required to maintain the leases from year to year.

(2) Includes the Company's contractual payment obligations for (i) social projects such as the Sonangol Research and Technology Center and academic scholarships for Angolan students that the Company was and is contractually obligated to pay in consideration for the Angolan government granting it the licenses to explore for and develop hydrocarbons offshore Angola and (ii) the Company's remaining work program obligations on Block 9 offshore Angola. Pursuant to the terms of the Risk Services Agreements for Blocks 9 and 21 and the Production Sharing Agreement for Block 20, the Company is not required to pay annual rental payments to maintain the licenses from year to year.

The Company recorded $12.8 million, $6.7 million, and $12.1 million of office and delay rental expense for the years ended December 31, 2014, 2013 and 2012, respectively.

18. Segment Information

The Company currently has two geographic operating segments for its operations. The operating segments are focused in the deepwater U.S. Gulf of Mexico and offshore West Africa. The following

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18. Segment Information (Continued)

tables provide the geographic operating segment information for years ended December 31, 2014, 2013 and 2012:

	United States	West Africa	Total
		($ in thousands)	
Year ended December 31, 2014			
Operating costs and expense	$ 238,214	$ 203,727	$ 441,941
Operating income (loss)	(238,214)	(203,727)	(441,941)
Other income (expense)			(68,822)
Net income (loss)			$ (510,763)
Additions to Property and Equipment, net(1)	$ 135,449	$ 320,637	$ 456,086
Year ended December 31, 2013			
Operating costs and expense	$ 329,832	$ 202,852	$ 532,684
Operating income (loss)	(329,832)	(202,852)	(532,684)
Other income (expense)			(56,340)
Net income (loss)			$ (589,024)
Additions to Property and Equipment, net(1)	$ 44,124	$ 332,395	$ 376,519
Year ended December 31, 2012			
Operating costs and expense	$ 231,196	$ 53,632	$ 284,828
Operating income (loss)	(231,196)	(53,632)	(284,828)
Other income (expense)			1,829
Net income (loss)			$ (282,999)
Additions to Property and Equipment, net(1)	$ 67,068	$ 169,362	$ 236,430

(1) These amounts are net of accumulated allowance for impairment on oil and gas properties and accumulated depreciation and amortization on other property and equipment.

19. Contingencies

The Company is currently, and from time to time may be, subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. It is not presently possible to determine whether any such matters will have a material adverse effect on the Company's consolidated financial position, results of operations, or liquidity.

20. Other Matters

As previously disclosed, in November 2011 a formal order of investigation was issued by the SEC related to our operations in Angola. In August 2014, we received a Wells Notice from the SEC related to this investigation. In January 2015, we received a termination letter from the SEC advising us that the SEC's FCPA investigation has concluded and the Staff does not intend to recommend any enforcement action by the SEC. This letter formally concluded the SEC's investigation. We continue to

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

20. Other Matters (Continued)

cooperate with the Department of Justice ("DOJ") with regard to its ongoing parallel investigation. We are unable to predict the outcome of the DOJ's ongoing investigation or any action that the DOJ may decide to pursue.

21. Related Party Transactions

On February 20, 2013, the Company entered into software licensing and consulting service agreements with Quorum Business Solutions, Inc. ("Quorum") and Quorum Business Solutions (U.S.A.), Inc, related to certain enterprise resource planning software. Under these agreements, Quorum will license, host, and support this software for us for an initial term of three years. The approximate value of these agreements is $1.5 million. Quorum is owned in part by Riverstone Holdings, LLC, one of our former financial sponsors. For the years ended December 31, 2014 and 2013, the Company incurred a total of 1.5 million and $1.3 million, respectively, in costs relating to Quorum. The Company did not have any material related party transactions for the year ended December 31, 2012.

22. Selected Quarterly Financial Data—Unaudited

Unaudited quarterly financial data for the years ended December 31, 2014 and 2013 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	($ in thousands, except per share data)			
Year ended December 31, 2014				
Operating costs and expenses	$ 47,293	$ 77,591	$ 120,961	$ 196,097
Operating income (loss)	(47,293)	(77,591)	(120,961)	(196,097)
Net income (loss)	(56,915)	(94,756)	(142,529)	(216,564)
Basic and diluted income (loss) per common share(1)	$ (0.14)	$ (0.23)	$ (0.35)	$ (0.53)
Year ended December 31, 2013				
Operating costs and expenses	$ 112,452	$ 65,365	$ 145,663	$ 209,204
Operating income (loss)	(112,452)	(65,365)	(145,663)	(209,204)
Net income (loss)	(128,087)	(78,818)	(160,000)	(222,119)
Basic and diluted income (loss) per common share(1)	$ (0.31)	$ (0.19)	$ (0.39)	$ (0.55)

(1) Totals may not add due to rounding.

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited)

The unaudited supplemental information on oil and gas exploration activities that follows is presented in accordance with supplemental disclosure requirements under ASC No. 932, *"Extractive Activities—Oil and Gas"* ("ASC No. 932") and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting.* Disclosures include (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Since the Company did not have any production activities for years ended December 31, 2014, 2013

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

and 2012, there will be no disclosures on results of operations related to oil and gas producing activities.

Capitalized Costs Related to Oil and Gas Activities

	U.S. Gulf of Mexico	West Africa	Total
		($ in thousands)	
As of December 31, 2014			
Unproved properties(1)	$ 699,426	$ 1,249,556	$ 1,948,982
Accumulated valuation allowance	(208,724)	(2,500)	(211,224)
	490,702	1,247,056	1,737,758
Proved properties	183,221	—	183,221
Net capitalized costs	$ 673,923	$ 1,247,056	$ 1,920,979
As of December 31, 2013			
Unproved properties	$ 605,658	$ 927,059	$ 1,532,717
Accumulated valuation allowance	(160,913)	—	(160,913)
	444,745	927,059	1,371,804
Proved properties	92,579	—	92,579
Net capitalized costs	$ 537,324	$ 927,059	$ 1,464,383

(1) Unproved properties include capitalized costs net of sale/like-kind exchange of leasehold interest transactions that occurred in 2014 and 2013 of approximately $5.6 million and $10.7 million, respectively, for the U.S. Gulf of Mexico. No gain or loss was recognized for these transactions for the years ended December 31, 2014 and 2013.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

Costs Incurred in Oil and Gas Activities

The following table reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration and development activities:

	U.S. Gulf of Mexico	West Africa	Total
		($ in thousands)	
Year ended December 31, 2014			
Property acquisition			
Unproved	$ 27,784	$ —	$ 27,784
Proved	—	—	—
Exploration			
Capitalized	150,396	423,704	574,100
Expensed	31,531	54,036	85,567
Development	90,642	—	90,642
Total Costs Incurred	$ 300,353	$ 477,740	$ 778,093
Year ended December 31, 2013			
Property acquisition			
Unproved	$ 37,584	$ —	$ 37,584
Proved	—	—	—
Exploration			
Capitalized	158,806	469,879	628,685
Expensed	48,688	25,525	74,213
Development	54,133	—	54,133
Total Costs Incurred	$ 299,211	$ 495,404	$ 794,615
Year ended December 31, 2012			
Property acquisition			
Unproved	$ 19,961	$ —	$ 19,961
Proved	—	—	—
Exploration			
Capitalized	178,295	168,309	346,604
Expensed	32,874	28,709	61,583
Development	—	—	—
Total Costs Incurred	$ 231,130	$ 197,018	$ 428,148

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

All of the Company's proved reserves are located in the U.S. Gulf of Mexico. Reserve quantity information for the years ended December 31, 2014, 2013 and 2012 are as follows:

	Natural Gas (in Bcf)	Oil and Condensate (in MMBbls)	Equivalent Volumes (in MMBOE)
Proved undeveloped reserves:			
Balance at December 31, 2012	—	—	—
Discoveries	3.4	7.9	8.5
Balance at December 31, 2013	3.4	7.9	8.5
Revisions	0.3	0.5	0.5
Balance at December 31, 2014	3.7	8.4	9.0

The reserves as of December 31, 2014 presented above were prepared by the independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). These reserves are located in the U.S. Gulf of Mexico. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine the Company's proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of the Company's fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company follows the guidelines prescribed in ASC No. 932 for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and natural gas properties as of December 31, 2014 and 2013. The Company did not have proved reserves as of December 31, 2012. These estimates were prepared by NSAI.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

(1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

(2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves.

(3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred.

(4) Future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves.

(5) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the U.S. Generally Accepted Accounting Principles. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Prices used in the report prepared by NSAI are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil volumes, the average Light Louisiana Sweet spot price of $98.48 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $4.350 per MMbtu is adjusted for energy content, transportation fees, and a regional price differential. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are $95.24 per barrel of oil and $4.770 per Mcf of gas.

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Cobalt International Energy, Inc.

Notes to Consolidated Financial Statements (Continued)

23. Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) (Continued)

Information with respect to the Company's estimated discounted future net cash flows related to its proved oil and natural gas reserves as of December 31, 2014 and 2013 are as follows:

	2014	2013
	($ in thousands)	
Future cash inflows	$ 814,394	$ 830,287
Future production costs	(12,710)	(6,400)
Future development costs	(244,306)	(302,278)
Future income tax expense(1)	—	—
Future net cash flows	557,378	521,609
10% annual discount for estimated timing of cash flows	(192,094)	(244,976)
Standardized measure of discounted future net cash flows	$ 365,284	$ 276,633

(1) There is no future income tax expense as of December 31, 2014, as the tax basis of the oil and gas properties in the United States and net operating losses attributable to oil and gas operations exceed the future net revenues.

Information with respect to the Company's standardized measure of discounted future net cash flows as of December 31, 2014 and 2013 are as follows:

	2014	2013
	($ in thousands)	
Standardized measure, beginning	$ 276,633	$ —
Discoveries	—	276,633
Revisions of previous estimates:	—	—
Changes in prices and costs	(36,869)	—
Changes in future development costs	49,700	—
Changes in quantities	17,351	—
Accretion of discount	27,663	—
Changes in timing and other	30,806	—
Standardized measure, ending	$ 365,284	$ 276,633

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Exhibit Index

Exhibit Number	Description of Document
	Certificate of Incorporation, Bylaws and Specimen Stock Certificate
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
3.2	By-laws of the Company (incorporated by reference to Exhibit 3 to the Company's Registration Statement on Form 8-A filed December 11, 2009 (File No. 001-34579))
4.1	Specimen stock certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Instruments relating to Debt Securities
4.2	Senior Debt Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.3	First Supplemental Indenture, dated as of December 17, 2012 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.4	Form of 2.625% Convertible Senior Note due 2019 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed December 17, 2012 (File No. 001-34579))
4.5	Second Supplemental Indenture, dated as of May 13, 2014 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
4.6	Form of 3.125% Convertible Senior Note due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed May 13, 2014 (File No. 001-34579))
	Operating Agreements
10.1	Risk Services Agreement relating to Block 9, between CIE Angola Block 9 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.2	Risk Services Agreement relating to Block 21, between CIE Angola Block 21 Ltd., Sonangol, Sonangol Pesquisa e Produção, S.A., Nazaki Oil and Gás and Alper Oil, Lda (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.3	Production Sharing Contract, dated December 20, 2011, between CIE Angola Block 20 Ltd., Sociedade Nacional de Combustíveis de Angola—Empresa Pública, Sonangol Pesquisa e Produção, S.A., BP Exploration Angola (Kwanza Benguela) Limited, and China Sonangol International Holding Limited (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.4	Exploration and Production Sharing Contract, dated December 13, 2006, between the Republic of Gabon and Total Gabon, S.A. (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

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Exhibit Number	Description of Document
10.5	Assignment Agreement, dated November 29, 2007, between CIE Gabon Diaba Ltd. and Total Gabon, S.A. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.6	Simultaneous Exchange Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.7	Gulf of Mexico Program Management and AMI Agreement, dated April 6, 2009, between the Partnership and TOTAL E&P USA, INC. (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed October 9, 2009 (File No. 333-161734))
10.8	Offshore Daywork Drilling Contract, dated May 3, 2008, between the Partnership and Ensco Offshore Company (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.9	International Daywork Drilling Contract—Offshore, dated November 8, 2010 between CIE Angola Block 21 Ltd. and Z North Sea Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.10	Offshore Drilling Contract between CIE Angola Block 21 Ltd. and Universal Energy Resources, Inc., dated July 30, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 30, 2012 (File No. 001-34579))
10.11	Offshore Drilling Contract between Cobalt International Energy, L.P. and Rowan Reliance Limited, dated August 5, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed October 29, 2013 (File No. 001-34579))
	Agreements with Stockholders and Directors
10.12	Amended and Restated Stockholders Agreement, dated February 21, 2013, among the Company and the stockholders that are signatory thereto (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.13	Registration Rights Agreement, dated December 15, 2009, among the Company and the parties that are signatory thereto (incorporated by reference to Exhibit 10.31 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.14	Form of Director Indemnification Agreements (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
	Management Contracts/Compensatory Plans or Arrangements
10.15†	Amended and Restated Long Term Incentive Plan of the Company (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.16†	Form of Restricted Stock Award Agreements relating to the Class B interests (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.17†	Form of Restricted Stock Award Agreements relating to the Class C interests (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))

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Exhibit Number	Description of Document
10.18†	Form of Restricted Stock Award Agreements relating to the Class D interests (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1/A filed October 29, 2009 (File No. 333-161734))
10.19†	Form of Non-Qualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.26 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.20†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K filed March 1, 2011 (File No. 001-34579)).
10.21†	Deferred Compensation Plan of the Company (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed February 26, 2013 (File No. 001-34579))
10.22†	Annual Incentive Plan of the Company (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 30, 2010 (File No. 001-34579))
10.23†	Employment Agreement, dated November 12, 2009, among the Company, the Partnership and Joseph H. Bryant (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.24†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James H. Painter (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.25†	Employment Agreement, dated October 23, 2009, among the Company, the Partnership and James W. Farnsworth (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.26†	Severance Agreement, dated October 23, 2009, among the Company, the Partnership and John P. Wilkirson (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed November 27, 2009 (File No. 333-161734))
10.27†	Employment Agreement, dated September 6, 2011, between the Company and Van P. Whitfield (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed September 8, 2011 (File No. 001-34579))
10.28†	Severance Agreement, dated April 1, 2010, between the Company and Michael D. Drennon (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K filed February 21, 2012 (File No. 001-34579))
10.29†	Form of Amendment to Employment Agreements with Joseph H. Bryant, James H. Painter and James W. Farnsworth and Severance Agreements with Samuel H. Gillespie and John P. Wilkirson (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed November 12, 2010 (File No. 001-34579)).
10.30†	Non-Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.31†	Non-Employee Directors Deferral Plan (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K filed January 29, 2010 (File No. 001-34579))
10.32†	Form of Restricted Stock Unit Award Notification under the Non- Employee Directors Compensation Plan (incorporated by reference to Exhibit 99.4 to the Company's Current Report on Form 8-K filed January 29, 2010 (Filed No. 001-34579))
10.33†*	Employment Agreement Extension, dated November 3, 2014, between the Company and Van P. Whitfield

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Exhibit Number	Description of Document
10.34†*	Employment Agreement, dated November 3, 2014, between the Company and James W. Farnsworth
10.35†*	Employment Agreement, dated November 3, 2014, between the Company and James H. Painter
10.36†*	Form of Special Restricted Stock Award Agreement, dated January 15, 2015
10.37†*	Form of Special Non-Qualified Stock Option Award Agreement, dated January 15, 2015
10.38†*	Form of Stock Appreciation Right Award Agreement under the Company's Long Term Incentive Plan
10.39†*	Form of Restricted Stock Unit Award Agreement under the Company's Long Term Incentive Plan
10.40†*	Form of Restricted Stock Award Agreement under the Company's Long Term Incentive Plan
	Other Exhibits
12.1*	Statement re: Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a- 14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith.

† Management contract or compensatory plan or arrangement required to be filed as an exhibit to this Form 10-K pursuant to Item 15(b).

Exhibit 10.33

November 3, 2014

Van P. Whitfield
Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, TX 77024

Dear Van:

In accordance with the notification requirements of Section 15.07 of your employment agreement with Cobalt International Energy, Inc. (the "**Company**") dated as of September 6, 2011 (the "**Employment Agreement**"), and notwithstanding the terms of Section 2.02(b) thereof, we hereby request that you continue to be employed with us pursuant to the terms of the Employment Agreement, as modified hereby, until December 31, 2015.

In connection with the extension of the Employment Agreement, and in consideration for the promises and covenants contained therein, including those promises and covenants contained in Articles 10 and 11, you shall receive on January 15, 2015 an equity award granted pursuant to the terms of the Company's Long Term Incentive Plan (the "**Plan**"). The award shall have a target value of $2,000,000 and shall be awarded 50% in the form of stock options to purchase shares of the Company's common stock and 50% in the form of restricted shares of the Company's common stock. Vesting of the stock option award and vesting of the restricted stock award shall require satisfaction of both a service condition and a performance condition. The service condition under each award shall be satisfied on December 31, 2015, subject to your continued employment through such date, and the performance condition shall be satisfied subject to the attainment of a $23.06 closing share price of the Company's common stock for a period of at least 20 out of 30 continuous days on which the shares are quoted or traded at any time during the ten-year term of each award. These awards shall be governed by the terms and conditions of the Plan and the terms and conditions set forth in the applicable award agreement. You agree that you are not otherwise entitled to these awards, and that these awards provide you with an interest in the Company that you would not otherwise have. You also agree that these awards are good and valuable consideration, which are intended to, and do, protect the Company's interests, including, but not limited to, non-public, confidential, and proprietary information, trade secrets, the Company's Business (as defined in the Employment Agreement), and goodwill. You also agree that such consideration is reasonably related to the interests described above, which are worthy of protection.

Notwithstanding the terms of the Plan or any applicable award agreement thereunder, subject to your continuing employment under the Employment Agreement, as modified hereby, until December 31, 2015, on such date, all of your time-vesting awards of restricted stock, restricted stock units, if applicable, and stock options under the Plan that remain outstanding as of December 31, 2015 shall fully vest; *provided* that the vested shares underlying such awards may not be Transferred (as defined below) until the regular scheduled vesting date(s) set forth in the award agreement(s) applicable to such award(s) and further, such vested shares shall be subject to forfeiture if you materially breach the covenants set forth in Article 10 or Article 11 of the Employment Agreement. "**Transfer**" means (a) offer, sell, pledge or hypothecate any legal or beneficial interest, including the grant of an option or other right, or otherwise transfer or enter into an agreement to do so or (b) enter into any hedge, swap or any other agreement that transfers, in whole or in part, any of the economic consequences of ownership (whether such transaction is settled by delivery of cash, shares or otherwise); *provided* that you may sell a sufficient number of vested shares in order to satisfy the income tax obligations that you will incur in connection with the vesting of such awards on December 31, 2015.

Van, as always, I truly value your leadership and the continued positive impact on all phases of our business. Please indicate that you agree to extend your Employment Agreement pursuant to its terms as modified hereby by executing below.

Sincerely,

/s/ Joseph H. Bryant

Joseph H. Bryant

Chairman and Chief Executive Officer

Cobalt International Energy, Inc.

Agreed and accepted:

/s/ Van P. Whitfield

Van P. Whitfield

November 3, 2014

Date

Exhibit 10.34

EMPLOYMENT AGREEMENT

dated as of November 3, 2014,

between

COBALT INTERNATIONAL ENERGY, INC.,
(*the Company*)

and

JAMES W. FARNSWORTH,
(*Employee*)

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INJUNCTIVE RELIEF

ARTICLE 15

NON-DISPARAGEMENT

ARTICLE 16

GENERAL

EMPLOYMENT AGREEMENT

This EMPLOYMENT AGREEMENT (this "**Agreement**") dated as of November 3, 2014 ("**Effective Date**"), is made by and between COBALT INTERNATIONAL ENERGY, INC., a Delaware corporation (the "**Company**"), and James W. Farnsworth, ("**Employee**") (jointly referred to herein as the "Parties").

RECITALS

WHEREAS, the Company and Employee are party to an employment agreement dated October 23, 2009 (the "**Prior Agreement**") that is scheduled to expire on December 21, 2014;

WHEREAS, the Compensation Committee of the Board of Directors of the Company has approved the Company's entering into this Agreement with Employee to pay for Employee's services and in exchange for the promises and covenants herein;

WHEREAS, this Agreement shall supersede the Prior Agreement except as set forth in Section 2.02 and 4.01 herein.

WHEREAS, during the course of Employee's employment, Company has provided and will continue to provide Employee with non-public, confidential, and proprietary information developed by the Company relating to the Company's Business, interests, methods, business plans, finances, and operations;

WHEREAS, the Board of Directors of the Company (the "**Board**") and its designated committee(s) intends to encourage Employee's continued service to the Company, Employee's participation in the Company's succession planning for Employee's position, and the development of the Company's short and long-term Business (as defined in Section 11.01(a) of this Agreement), interests, goals, and goodwill;

WHEREAS, the Company invests considerable resources in building partner, vendor, supplier, banking, financier, and investor relationships, and developing strategic plans and goodwill in the energy industry, not only by paying for Employee's services and investing in the development of Employee, but also by investing in research and development, and exploration techniques and technologies which are non-public, confidential, and proprietary;

WHEREAS, the Company and Employee acknowledge that the breadth and scope of the Company's operations covers a global territory due to the nature of the oil and natural gas exploration business, the Company's operations and Business, exploration goals and strategies, which Employee has had access to and will continue to have access to in order to perform Employee's duties; and

WHEREAS, the Company and Employee agree and understand that this Agreement and the mutual promises and covenants herein are intended to, and do, advance the interests of the Company, including but not limited to the Company's goodwill, growth, strategy, and development, and also the interests of Employee, and are also reasonable and necessary to protect Company's Business, confidential and proprietary information, and goodwill.

AGREEMENT

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration set forth herein, the sufficiency of which is acknowledged by the Parties, the Company and Employee agree as follows:

ARTICLE 1
DEFINITIONS

Section 1.01. *Definitions.*

"**Accrued Obligations**" shall mean Employee's base salary through the Date of Termination of Employment not theretofore paid, any expenses owed to Employee under the Company's expense reimbursement policy as in effect from time to time, any accrued vacation pay owed to Employee pursuant to the Company's vacation policy as in effect from time to time, any earned but unpaid annual performance bonus with respect to a calendar year that has ended on or before the Date of Termination of Employment (it being understood that a bonus will not be considered to have been unearned merely because Employee has not remained employed through the payment date so long as Employee has remained employed through the end of the calendar year that has ended on or before the Date of Termination of Employment), any amount accrued and arising from Employee's participation in, or benefits accrued under, any employee benefit plans, programs or arrangements maintained by the Company which amounts shall be payable in accordance with the terms and conditions of such employee benefit plans, programs or arrangements, and such other or additional benefits as may be, or become, due to Employee under the applicable terms of applicable plans, programs, agreements, corporate governance documents and other arrangements of the Company and its Affiliates and subsidiaries.

"**Affiliate**" shall mean any entity that owns or controls, is owned or controlled by, or is under common control with, the Company. An entity is deemed to control another if it owns, directly or indirectly, at least 50% of: (i) the shares entitled to vote at a general election of directors of such other entity, or (ii) the voting interest in such other entity if such entity does not have either shares or directors.

"**Agreement Termination Date**" shall mean the last day of the Employment Term.

"**Annual Bonus**" shall have the meaning assigned to such term in Section 6.02.

"**Annualized Base Salary**" shall mean an amount equal to the greater of:

Employee's annualized base salary at the rate in effect on the date of his Involuntary Termination or termination by reason of death or Disability, as applicable;

Employee's annualized base salary at the rate in effect 90 days prior to the date of his Involuntary Termination or termination by reason of death or Disability, as applicable; or

Employee's annualized base salary at the rate in effect immediately prior to a Change in Control if, on the date upon which such Change in Control occurs or within two years thereafter, Employee's employment shall be subject to an Involuntary Termination or be terminated by reason of death or Disability.

Annualized Base Salary shall not include any bonuses, incentive compensation, or equity-based compensation.

"**Base Salary**" shall have the meaning assigned to such term in Section 6.01.

"**Board**" shall have the meaning assigned to such term in the Recitals.

"**Cause**" shall mean:

(i) The willful failure of Employee to substantially perform Employee's duties as an employee of the Company (other than any such failure resulting from Employee's physical or mental incapacity),

(ii) Employee's having engaged in willful misconduct, gross negligence or a breach of fiduciary duty that results in material and demonstrable harm to the Company or any of its Affiliates,

(iii) Employee's willful and material breach of this Agreement (as amended from time to time) that results in material and demonstrable harm to the Company or any of its Affiliates,

(iv) Employee's having been convicted of, or having entered a plea bargain or settlement admitting guilt or the imposition of unadjudicated probation for, any felony under the laws of the United States, any state or the District of Columbia, where such felony involves

moral turpitude or where, as a result of such felony, the continued employment of Employee would have, or would reasonably be expected to have, a material adverse impact on the Company's or any of its Affiliates' reputations,

(v) Employee's having been the subject of any order, judicial or administrative, obtained or issued by the Securities and Exchange Commission, for any securities violation involving fraud including, for example, any such order consented to by Employee in which findings of facts or any legal conclusions establishing liability are neither admitted nor denied,

(vi) Employee's unlawful use (including being under the influence of) or possession of illegal drugs on the Company's or any of its Affiliate's premises or while performing Employee's duties and responsibilities as an employee of the Company, or

(vii) Employee's commission of an act of fraud, embezzlement, or misappropriation, in each case, against the Company or any of its Affiliates.

The provisions in this Agreement for termination (for Cause or otherwise) are set forth in more detail in Section 7.02, including provisions regarding notice and opportunity to cure.

For purposes of this definition, no act, or failure to act, on the part of Employee shall be considered "willful" unless it is done, or omitted to be done, by Employee in bad faith or without reasonable belief that Employee's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer of the Company (other than Employee if he is serving in such capacity) or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by Employee in good faith and in the best interests of the Company.

(a) "**Change in Control**" means the occurrence of any one or more of the following events:

(i) any "person" (as defined in Section 13(d) of the Securities Exchange Act of 1934 (the "**Act**")), other than an employee benefit plan or trust maintained by the Company, becomes the "beneficial owner" (as defined in Rule 13d-3 under the Act), directly or indirectly, of securities of the Company representing more than 50% of the combined voting power of the Company's outstanding securities entitled to vote generally in the election of directors;

(ii)at any time during a period of 12 consecutive months, individuals who at the beginning of such period constituted the Board and any new member of the Board whose election or nomination for election was approved by a vote of at least a majority of the directors then still in office who either were directors at the beginning of such period or whose election or nomination for election was so approved, cease for any reason to constitute a majority of members of the Board; or

(iii)the consummation of (A) a merger or consolidation of the Company or any of its subsidiaries with any other corporation or entity, other than a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or being converted into voting securities of the surviving entity or, if applicable, the ultimate parent thereof) at least 50% of the combined voting power and total fair market value of the securities of the Company or such surviving entity or parent outstanding immediately after such merger or consolidation, or (B) any sale, lease, exchange or other transfer to any Person (other than an affiliate (as defined in the Company Long Term Incentive Plan)) of assets of the Company and/or any of its subsidiaries, in one transaction or a series of related transactions, having an aggregate fair market value of more than 50% of the fair market value of the Company and its subsidiaries (the "**Company Value**") immediately prior to such transaction(s), but only to the extent that, in connection with such transaction(s) or within a reasonable period thereafter, the Company's stockholders receive distributions of cash and/or assets having a fair market value that is greater than 50% of the Company Value immediately prior to such transaction(s).

Notwithstanding the foregoing, in no event shall a Change in Control be deemed to have occurred with respect to Employee if Employee is part of a "group" within the meaning of Section 13(d)(3) of the Act that consummates the Change in Control transaction. In addition, for purposes of the definition of Change in Control, a person engaged in business as an underwriter of securities shall not be deemed to be the beneficial owner of, or to beneficially own, any securities acquired through such person's participation in good faith in a firm commitment underwriting until the expiration of 40 days after the date of such acquisition.

"**Code**" shall mean the Internal Revenue Code of 1986, as amended.

"**Date of Termination of Employment**" shall mean (i) if Employee's employment with the Company is terminated by his death, the date of Employee's death, or (ii) if Employee's employment with the Company is terminated for any reason whatsoever other than Employee's death, the earlier of the date indicated in the Notice of Termination of Employment or the date specified by the Company pursuant to Section 7.02.

"**Disability**" shall mean, at any time the Company or any Affiliate sponsors a long-term disability plan that covers Employee and other employees of the Company, "disability" as defined in such long-term disability plan for the purpose of determining a participant's eligibility for benefits; *provided, however*, if the long-term disability plan contains multiple definitions of disability, then "Disability" shall refer to that definition of disability which, if Employee qualified for such disability benefits, would provide coverage for the longest period of time. The determination of whether Employee has a Disability shall be made by the person or persons required to make final disability determinations under the long-term disability plan. At any time the Company or any Affiliate does not sponsor such a long-term disability plan, Disability shall mean Employee's inability to perform, with or without reasonable accommodation, the essential functions of his position with the Company for a total of three months during any six-month period as a result of incapacity due to mental or physical illness, as determined by a physician selected by the Company or its insurers and acceptable to Employee or Employee's legal representative, such agreement as to acceptability not to be unreasonably withheld or delayed. Any refusal by Employee to submit to a medical examination for the purpose of determining Disability shall be deemed to constitute conclusive evidence of Employee's Disability.

"**Effective Date**" shall have the meaning assigned to such term in the preamble of this Agreement.

"**Employment Term**" shall have the meaning assigned to such term in Section 2.01.

"**Good Reason**" shall mean the occurrence of any of the following events: (i) a material diminution in Employee's base salary or (ii) relocation of the geographic location of Employee's principal place of employment by more than 75 miles from Houston, Texas.

Notwithstanding the preceding provisions of this definition or any other provision in this Agreement to the contrary, any assertion by Employee of a termination of employment for "Good Reason" shall not be effective unless all of the following conditions precedent are satisfied: (A) the condition described in clauses (i) or (ii) of this definition giving rise to Employee's termination of employment must have arisen without Employee's consent; (B) Employee must provide written notice to the Company of such condition in accordance with Section 16.07 within 45 days of the initial existence of the condition; (C) the condition specified in such notice must remain uncorrected for 30 days after receipt of such notice by the Company; and (D) the date of Employee's termination of employment for Good Reason must occur within 90 days after the initial existence of the condition specified in such notice.

"**Inventions**" shall have the meaning assigned to such term in Article 13.

"**Involuntary Termination**" shall mean any termination of Employee's employment with the Company (i) by the Company without Cause or (ii) by Employee for Good Reason. "Involuntary Termination" shall not include a termination of Employee's employment with the Company for any other reason whatsoever, including, without limitation: (A) by the Company for Cause, (B) by Employee without Good Reason, or (C) as a result of Employee's death or Disability.

"**Long Term Incentive Plan**" shall mean the Cobalt International Energy, Inc. Long Term Incentive Plan as in effect from time to time or any successor plan thereto.

"**Non-Compete Period**" shall have the meaning assigned to such term in Section 11.01(a).

"**Notice of Non-Renewal**" shall have the meaning assigned to such term in Section 7.04.

"**Notice of Termination of Employment**" shall have the meaning assigned to such term in Section 7.02.

"**Prior Agreement**" shall have the meaning assigned to such term in the Recitals of this Agreement.

"**Pro Rata Bonus**" shall mean an amount equal to the product of (i) the actual annual bonus Employee would have been entitled to receive, based on the Company's actual performance through the end of the calendar year in which Employee's termination of employment with the Company occurred, determined as if he had continued his employment with the Company through the end of such calendar year and (ii) a fraction, the numerator of which is the number of days during the calendar year through the date of Employee's termination of employment with the Company and the denominator of which is 365.

"**Pro Rata Bonus Payment Date**" shall mean, with respect to a Pro Rata Bonus for a particular calendar year, the date on which annual bonuses for such calendar year are generally paid to employees of the Company who have not terminated employment with the Company, but in no event earlier than January 1 of the year following such calendar year nor later than December 31 of the year following such calendar year.

"**Renewal Date**" shall have the meaning assigned to such term in Section 2.01.

"**Separation from Service**" means, with respect to Employee, the (i) cessation of all services performed by Employee for the Company or (ii) permanent decrease in the level of services performed by Employee for the Company (whether as an employee or as an independent contractor) to no more

than 20 percent of the average level of services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Company, if Employee has been providing services to the Company for less than 36 months).

"**Severance Amount**" shall mean (i) if Employee incurs an Involuntary Termination prior to a Change in Control or on or after the second anniversary of the Change in Control (to the extent applicable), 100% of Annualized Base Salary and (ii) if Employee incurs an Involuntary Termination on the date of the Change in Control or prior to the second anniversary of the Change in Control, 100% of Annualized Base Salary.

"**Transfer**" shall have the meaning assigned to such term in Section 9.01.

ARTICLE 2
EFFECTIVENESS; TERM OF AGREEMENT;
TERMINATION OF PRIOR AGREEMENT

Section 2.01. *Effectiveness; Term of Agreement.* This Agreement is effective as of the Effective Date, referenced in the preamble of this Agreement, and shall continue until December 31, 2016, unless terminated earlier pursuant to Article 7 of this Agreement; *provided* that, on December 31, 2016 and each annual anniversary thereafter (such date and each annual anniversary thereof, a "**Renewal Date**"), this Agreement shall automatically extend, upon the same terms and conditions, for successive periods of one year, unless either party provides written notice of its intention not to extend the term of the Agreement at least 30 days prior to the applicable Renewal Date. The period during which Employee is employed by the Company is referred to as the "**Employment Term**". The covenants contained in Articles 11, 12, 13, 14, and 15 shall remain enforceable past the Employment Term, as specifically set forth in those Articles.

Section 2.02. *Termination of Prior Agreement; Continuing Effectiveness of Transfer Restrictions.* The Prior Agreement shall be of no further force or effect upon the Effective Date of this Agreement, except for the transfer restrictions set forth in Annex II of the Prior Agreement, which shall remain in full force and effect pursuant to the terms thereof and are incorporated herein by reference. By entering into this Agreement, Employee hereby agrees to continue to be bound by the transfer restrictions set forth in Annex II of the Prior Agreement.

ARTICLE 3
POSITIONS AND DUTIES

Section 3.01. *Employment; Positions.* Employee shall be employed as Chief Exploration Officer and Executive Vice President, Exploration and New

Ventures of the Company. The Company may subsequently assign Employee to a different position with the Company or any Affiliate of the Company or modify Employee's duties and responsibilities; *provided* that any assignment of a new position or modification of Employee's duties or responsibilities shall be subject to Employee's consent, which consent may not be unreasonably withheld so long as the new position reasonably relates to Employee's experience and existing position. With respect to reporting relationships, Employee currently reports to the Company's Chief Operating Officer. In the event that executive leadership changes at the Company would otherwise result in Employee reporting to anyone other than the Company's current Chief Operating Officer, the Company will take the necessary steps to mitigate any of Employee's concerns with respect to reporting relationships, including Employee reporting directly to the Company's Chief Executive Officer.

Section 3.02. *Duties and Services.* Employee agrees to serve in the position(s) assigned pursuant to Section 3.02 and to perform diligently and to the best of Employee's abilities the duties and services pertaining to such position(s), as well as such additional duties and services that the Company may reasonably direct Employee. Employee's employment shall also be subject to the policies maintained and established by the Company that are of general applicability to the Company's employees.

Section 3.03. *Succession Planning.* Employee agrees that Employee's duties and services to the Company include participating in good faith in the Company's succession planning for Employee's position, as directed by the Company's Chief Executive Officer. Employee's succession planning responsibilities may include, but are not limited to, Employee's collaboration with the Company in identifying, evaluating and developing a successor for Employee's position, as well as facilitating a smooth transition to such successor.

Section 3.04. *Other Interests.* Employee agrees, during the period of Employee's employment by the Company, to devote substantially all of Employee's business time, energy and best efforts to the business and affairs of the Company and its Affiliates. Notwithstanding the foregoing, the parties acknowledge and agree that Employee may (a) engage in and manage Employee's passive personal investments, (b) engage in charitable and civic activities and (c) serve on corporate boards and committees of for-profit companies, so long as such activities do not conflict with the Business and affairs of the Company and its Affiliates or interfere with Employee's performance of Employee's duties.

ARTICLE 4
CERTAIN EMPLOYEE REPRESENTATIONS AND AGREEMENTS;
SPECIAL EQUITY GRANTS

Section 4.01. *Transfer Restrictions.* Employee agrees that Employee shall remain bound by the transfer restrictions set forth in Annex II to the Prior Agreement, which are incorporated herein by reference.

Section 4.02. *Life Insurance.* This Agreement constitutes written notice to Employee that (a) the Company or an Affiliate may insure Employee's life, (b) the Company or an Affiliate shall have the right to determine the amount of insurance and the type of policies, and (c) the Company or an Affiliate will be the beneficiaries of any proceeds payable under such policies upon the death of Employee. Employee hereby irrevocably consents to being insured under the policies described in the preceding sentence and to the coverage under such policies continuing after the termination of this Agreement and/or Employee's termination of employment with the Company and its Affiliates. Employee agrees and acknowledges that Employee shall not have the right to designate the beneficiary or beneficiaries of the death benefit payable pursuant to such policies, and neither Employee nor any other person claiming through Employee shall have any interest in such policies. Employee shall (i) furnish any and all information reasonably requested by the Company, any Affiliate or the insurer to facilitate the issuance of the life insurance policy or policies described in this paragraph or any adjustment to any such policy, and (ii) take such physical examinations as the Company, any Affiliate or the insurer deems necessary. Employee shall incur no financial obligation by executing any required document pursuant to this Section 4.02, and shall have no interest in any such policy.

Section 4.03. *Equity. Grant In Connection With Execution of This Agreement.* In consideration for the promises and covenants contained in this Agreement, including those promises and covenants contained in Articles 11 and 12, Employee shall receive on January 15, 2015 and on January 15, 2016, an equity award granted pursuant to the terms of the Company's Long Term Incentive Plan. Each award shall have a target value of $2,000,000 and shall be awarded 50% in the form of stock options to purchase shares of the Company's common stock and 50% in the form of restricted shares of the Company's common stock. Vesting of the stock option awards and vesting of the restricted stock awards shall require satisfaction of both a service condition and a performance condition. The service condition under each award shall be satisfied on December 31, 2016, subject to Employee's continued employment through such date, and the performance condition shall be satisfied subject to the attainment of a $23.06 closing share price of the Company's common stock for a period of at least 20 out of 30 continuous days on which the shares are quoted or traded at any time during the ten-year term of each award. These awards shall be governed by the terms and conditions of the Long Term Incentive Plan and the terms and conditions set forth in the applicable award agreement. Employee agrees that Employee is not

otherwise entitled to these awards, and that these awards provide Employee an interest in the Company that Employee would not otherwise have. Employee also agrees that these awards are good and valuable consideration, which are intended to, and do, protect the Company's interests, including, but not limited to, non-public, confidential, and proprietary information, trade secrets, the Company's Business, and goodwill. Employee also agrees that such consideration is reasonably related to the interests described above, which are worthy of protection. The Company agrees that these awards shall have no effect on the compensation and benefits set forth in Article 6.

Section 4.04. *Partial Forfeiture in the Event of Employee's Breach of Article 11 or Article 12*. In the event of a material breach by Employee of the covenants and promises regarding Noncompetition or Nonsolicitation contained in Article 11 or the covenants and promises regarding Nondisclosure of Confidential and Proprietary Information contained in Article 12, Employee shall forfeit to the Company all but 1,000 restricted shares of the Company's common stock and all outstanding stock options granted on January 15, 2015 and on January 15, 2016 in accordance with the terms of 4.03. In the event the Employee has already sold the restricted shares or stock at the time of said breach, Employee shall tender to the Company an amount equivalent to the sales price of all but 1,000 restricted shares of the Company's common stock granted in Section 4.03. Employee also agrees that the shares that are not subject to forfeiture, as set forth herein, are sufficient consideration that is reasonably related to protect the Company's interests described in Articles 11 and 12, and that those interests, including but not limited to the confidential information and goodwill, are worthy of protection. Nothing in this Section is intended to, nor does it, in any way limit any and all other remedies available to the Company at law or in equity.

ARTICLE 5
CONFIDENTIAL INFORMATION, INVENTIONS,
BUSINESS OPPORTUNITIES AND GOODWILL

Section 5.01. *Confidential Information, Inventions, Business Opportunities and Goodwill.* The Company has and shall continue to: (a) disclose to Employee, and place Employee in a position to have access to or develop, non-public, confidential, or proprietary information and Inventions of the Company (or those of the Company's Affiliates); (b) entrust Employee with business opportunities of the Company (or those of the Company's Affiliates; and (c) place Employee in a position to develop business goodwill on behalf of the Company (or of the Company's Affiliates). The Parties acknowledge and agree that the confidential or proprietary information that has been or will be received by Employee is essential to the performance of Employee's duties. The Parties further acknowledge and agree that the Company has expended many resources, including time and money, in developing its confidential and proprietary information, and that the consideration and promises made herein, including those in Article 11, 12, and 13

are reasonably related to the protection of the Company's confidential and proprietary information and other interests, including goodwill.

ARTICLE 6
COMPENSATION AND BENEFITS

Section 6.01. *Base Salary.* During the term of this Agreement, Employee shall receive a minimum, annualized base salary of an amount not less than the amount Employee was receiving as of the Agreement's Effective Date (the "**Base Salary**"). Employee's Base Salary shall be reviewed periodically by the Board (or a committee thereof) and, in the sole discretion of the Board (or a committee thereof), the Base Salary may be increased (but not decreased) effective as of any date determined by the Board (or a committee thereof). Employee's Base Salary shall be paid in equal installments in accordance with the Company's standard policy regarding payment of compensation to employees, but no less frequently than monthly.

Section 6.02. *Bonuses.* Employee shall be eligible to receive an annual, calendar-year bonus (payable in a single lump sum) based on criteria determined at the discretion of the Board (or a committee thereof) (the "**Annual Bonus**"), it being understood that (a) the target bonus at planned or targeted levels of performance shall equal to a percentage of Employee's Base Salary that is not less than the target percentage Employee was receiving as of the Agreement's Effective Date and (b) the actual amount of each Annual Bonus shall be determined at the discretion of the Board (or a committee thereof). The Company shall use commercially reasonable efforts to pay each Annual Bonus with respect to a calendar year on or before March 15 of the following calendar year (and in no event shall an Annual Bonus be paid after December 31 of the following calendar year).

Section 6.03. *Long-Term Equity Incentive Compensation.* On an annual basis, Employee shall be eligible to receive long term equity incentive awards under the Long Term Incentive Plan or any successor plan thereto.

Section 6.04. *Other Benefits.* During Employee's employment hereunder, Employee shall be permitted to participate in all benefit plans and programs of the Company, including improvements or modifications of the same, which are now, or may hereafter be, available to other senior Employees of the Company. The Company shall not, however, by reason of this Section 6.04, be obligated to institute, maintain, or refrain from changing, amending, or discontinuing, any such benefit plan or program, so long as such changes are similarly applicable to other senior employees generally.

Section 6.05. *Expenses.* The Company shall reimburse Employee for all reasonable business expenses incurred by Employee in performing services

hereunder, including all expenses of travel and living expenses while away from home on business or at the request of and in the service of the Company; provided, in each case, that such expenses are incurred and accounted for in accordance with the policies and procedures established by the Company. Any such reimbursement of expenses shall be made by the Company upon or as soon as practicable following receipt of supporting documentation reasonably satisfactory to the Company (but in any event not later than the close of Employee's taxable year following the taxable year in which the expense is incurred by Employee); provided, however, that, upon Employee's termination of employment with the Company, in no event shall any additional reimbursement be made prior to the date that is six months after Employee's termination of employment with the Company to the extent such payment delay is required under Section 409A(a)(2)(B)(i) of the Code.

Section 6.06. *Vacation and Sick Leave.* During Employee's employment hereunder, Employee shall be entitled to vacation and other paid time off in accordance with the Company's standard vacation and paid time off policy, as in effect from time to time.

Section 6.07. *Offices.* Subject to Articles 3 and 6, Employee agrees to serve without additional compensation, if elected or appointed thereto, as a director of the Company or any Affiliate and as a member of any committees of the board of directors of any such entities, and in one or more Employee positions of any Affiliate.

Section 6.08. *Clawback Provisions.* Notwithstanding any other provisions in this Agreement to the contrary, any incentive-based compensation, or any other compensation, paid to Employee pursuant to this Agreement or any other agreement or arrangement with the Company which is subject to recovery under any law, government regulation or stock exchange listing requirement, will be subject to such deductions and clawback as may be required to be made pursuant to such law, government regulation or stock exchange listing requirement (or any policy adopted by the Company pursuant to any such law, government regulation or stock exchange listing requirement). To the extent the clawback results in a deduction from wages or a final paycheck, Employee expressly authorizes the Company to make such deductions (pursuant to the Texas Payday Act).

ARTICLE 7
TERMINATION OF EMPLOYMENT; NOTICE OF TERMINATION OF EMPLOYMENT; NOTICE OF NON-RENEWAL

Section 7.01. *Termination of Employment.* Employee's employment with the Company may be terminated by the Company or Employee under the following circumstances: (a) Employee's death; (b) Employee's Disability; (c) termination by the Company for Cause; (d) termination by the Company

without Cause; (e) resignation by Employee for Good Reason; or (f) resignation by Employee without Good Reason. For all purposes of this Agreement, Employee shall be considered to have terminated employment with the Company when Employee incurs a Separation from Service.

Section 7.02. *Notice of Termination of Employment.* Any termination of Employee's employment by the Company or by Employee (other than termination by reason of Employee's death) shall be communicated in writing to the other party indicating the specific termination provision in the first sentence of Section 7.021 relied upon, setting forth in reasonable detail the facts and circumstances claimed to provide a basis for the termination of Employee's employment under the provision so indicated, and specifying a Date of Termination of Employment which, if submitted by Employee, shall be at least 30 days following the date of such notice (a "**Notice of Termination of Employment**"); *provided*, *however*, that in the case of any Notice of Termination of Employment submitted by Employee, the Company may, in its sole discretion, advance the Date of Termination of Employment to any date following the Company's receipt of the Notice of Termination of Employment (and, if the Date of Termination of Employment is so advanced, it shall not change the basis for Employee's termination nor be construed or interpreted as a termination of Employee's employment by the Company for any reason whatsoever). A Notice of Termination of Employment submitted by the Company may provide for a Date of Termination of Employment on the date Employee receives the Notice of Termination of Employment, or any date thereafter elected by the Company in its sole discretion. If the Company is terminating Employee's employment for Cause, the Company shall provide employee with a Notice of Termination of Employment and allow Employee 30 days following the date of such Notice of Termination to fully remedy, cure, or rectify, if possible, the situation giving rise to the Company's allegations of Cause. The cessation of employment of Employee shall not be deemed to be for Cause unless and until there shall have been delivered to Employee a copy of a resolution duly adopted by the affirmative vote of a majority of the entire membership of the Board (excluding Employee, if Employee is a member of the Board) at a meeting of the Board at which at least a quorum is present (after reasonable notice is provided to Employee and Employee is given an opportunity, together with counsel for Employee, to be heard before the Board) finding that, in the good faith opinion of the Board, Employee is guilty of the conduct described in this definition, and specifying the particulars thereof in detail. The failure by Employee or the Company to set forth in the Notice of Termination of Employment any fact or circumstance which contributes to a showing of Cause or Good Reason shall not waive any right of Employee or the Company hereunder or preclude Employee or the Company from asserting such fact or circumstance in enforcing Employee's or the Company's rights hereunder.

Section 7.03. *Deemed Resignations.* Unless otherwise agreed to in writing by the Company and Employee prior to the termination of Employee's employment, any termination of Employee's employment shall constitute an

automatic resignation of Employee: (i) as an officer of the Company and each Affiliate; (ii) as a member of the Board (if applicable); (iii) from the board of directors or similar governing body of any Affiliate; and (iv) from the board of directors or similar governing body of any corporation, limited liability entity or other entity in which the Company or any Affiliate holds an equity interest and with respect to which board or similar governing body Employee serves as the Company's or such Affiliate's designee or other representative.

Section 7.04. *Notice of Non-Renewal of This Agreement.* In accordance with Section 2.01 of this Agreement, an election by the Company or by Employee not to extend the Employment Term under this Agreement shall be communicated in writing to the other party hereto (a "**Notice of Non-Renewal**"). A Notice of Non-Renewal communicated by the Company or by Employee shall not constitute a Notice of Termination of Employment.

ARTICLE 8
SEVERANCE BENEFITS

Section 8.01. *Death, Disability, Termination for Cause or Resignation Without Good Reason.* If Employee's employment with the Company is terminated by the Company for Cause or by Employee without Good Reason, or if such employment terminates by reason of Employee's death or Disability, then, upon such termination, Employee (or Employee's estate) shall be entitled to receive the Accrued Obligations (other than in the case of a termination by the Company for Cause, any bonus or incentive compensation that under the applicable plan requires Employee to be employed on the date of payment). If Employee's employment with the Company terminates by reason of death or Disability, then the Company shall also pay to Employee (or Employee's estate or legal representatives, as applicable) on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus.

Section 8.02. *Involuntary Termination.* If Employee's employment with the Company is subject to an Involuntary Termination, Employee shall be entitled to receive the Accrued Obligations and, subject to the provisions of Section 16.09, the Company will, as additional compensation for services rendered to the Company (including its Affiliates), pay to Employee the following amounts and take the following actions after the last day of Employee's employment with the Company:

(a) if the Involuntary Termination occurs prior to a Change in Control or on or after the second anniversary of the Change in Control, pay to Employee in equal monthly installments an amount in cash equal to the Severance Amount, the first installment to be paid on the date that is 60 days after the date of Employee's termination of employment with the Company and subsequent installments to be paid on the first day of each of the next 11 calendar months

thereafter or such lesser number of installments such that no installment is paid after March 1st of the year following the year in which Employee's employment was terminated, with each installment equal to the Severance Amount divided by the total number of such installments to be paid;

(b)if the Involuntary Termination occurs on the date of a Change in Control or before the second anniversary of the Change in Control, pay to Employee on the date that is 60 days after the date of Employee's termination of employment with the Company a lump sum cash payment in an amount equal to the Severance Amount;

(c)pay to Employee on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus; provided, however, that this paragraph shall apply with respect to such Pro Rata Bonus only to the extent the applicable performance criteria have been satisfied as certified by a committee of the Board as required under Section 162(m) of the Code; and

(d)an additional lump sum cash payment in the amount of $25,000 to be paid on the same day as the first installment is paid pursuant to Section 8.02(a) (or, if applicable, on the same day as the lump sum cash payment is paid pursuant to Section 8.02(b)).

Section 8.03. *Death, Disability or Involuntary Termination After Agreement Termination Date.* If, after the Agreement Termination Date but prior to the payment date of the Annual Bonus for the calendar year in which the Agreement Termination Date occurs, Employee's employment with the Company terminates by reason of the Employee's death or by reason of what would have otherwise qualified as Disability or an Involuntary Termination under this Agreement if this Agreement was still in effect at the time of such termination of employment, the Company shall pay to Employee (or Employee's estate or legal representatives, as applicable), subject to the provisions of Section 16.09, on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus.

ARTICLE 9
VESTING OF CERTAIN EQUITY-BASED AWARDS UPON EXPIRATION OF INITIAL TERM OF THIS AGREEMENT

Section 9.01. *Vesting of Certain Equity-Based Awards.* Notwithstanding the terms of the Company's Long Term Incentive Plan or any applicable award agreement thereunder, subject to Employee's continuing employment hereunder until December 31, 2016, on such date, all of Employee's time-vesting awards of restricted stock, restricted stock units, if applicable, and stock options under the Company's Long Term Incentive Plan that remain outstanding as of December 31, 2016 shall fully vest; *provided* that the vested shares underlying such awards may not be Transferred (as defined

below) until the regular scheduled vesting date(s) set forth in the award agreement(s) applicable to such award(s) and further, such vested shares shall be subject to the forfeiture provision contain in Section 4.04 if Employee materially breaches the covenants set forth in Article 11 or Article 12. "**Transfer**" means (a) offer, sell, pledge or hypothecate any legal or beneficial interest, including the grant of an option or other right, or otherwise transfer or enter into an agreement to do so or (b) enter into any hedge, swap or any other agreement that transfers, in whole or in part, any of the economic consequences of ownership (whether such transaction is settled by delivery of cash, shares or otherwise); *provided* that Employee may sell a sufficient number of vested shares in order to satisfy the income tax obligations that Employee will incur in connection with the vesting of such awards on December 31, 2016.

ARTICLE 10
INTEREST ON LATE PAYMENTS

Section 10.01. *Interest on Late Payments.* If any payment provided for in Section 8.02(a), (b) or (c) or Section 8.03 is not made when due, then the Company shall pay to Employee interest on the amount payable from the date that such payment should have been made under such section until such payment is made, which interest shall be calculated at 5% plus the prime rate of interest announced by JPMorgan Chase Bank, or any successor thereto, at its principal office in New York, and shall change when and as any such change in such prime rate shall be announced by such bank, or any successor thereto.

ARTICLE 11
COMPETITION

Section 11.01. *Competition.* Employee and the Company agree to the restrictive covenants of this Article 11: (i) in consideration for the confidential information provided by the Company to Employee pursuant to Article 5 or otherwise during the course of his employment; (ii) as part of the consideration for the compensation and benefits to be paid to Employee by the Company; (iii) in consideration for the vesting of equity-based awards provided pursuant to Section 9.01; (iv) to reasonably protect the trade secrets and confidential and proprietary information of the Company disclosed or entrusted to Employee by the Company and the goodwill of the Company, or its Affiliates and subsidiaries, developed through the efforts of Employee and/or the business opportunities disclosed or entrusted to Employee by the Company; and (v) as an additional incentive for the Company to enter into this Agreement.

(a)As used in this Article 11, (i) the term "**Company**" shall include the Company and its Affiliates and subsidiaries, and (ii) the term "**Business**" shall mean the exploration for, and the development and production of, oil and natural

gas and the acquisition of leases and other real property in connection therewith, as such business may be expanded or altered by the Company during the period of Employee's employment by the Company; *provided*, that any business or endeavor shall cease to be the "Business" if the Company is not or ceases to be engaged in such business or endeavor.

(b) Employee shall not at any time while employed by the Company and for a 1-year period following the Date of Termination of Employment (the "**Non-Compete Period**") directly or indirectly provide any service (whether as director, officer, employee, agent, representative, consultant or otherwise) in any geologic basin in which the Company has material Business interests that involve the use of similar geologic concepts employed by the Company in such geologic basin at the time in question.

(c) During the Non-Compete Period, Employee shall not, directly or indirectly, recruit or otherwise solicit or induce any employee of the Company, (i) to terminate or forego his or her actual or prospective employment with the Company, or (ii) to establish any relationship with Employee or any of Employee's affiliates, employers, or prospective employers, for any business purpose competitive with the Business of the Company; or (iii) provide the name(s) and/or contact information of any current employee of the Company to Employee's potential or subsequent employer(s), *provided*, *however*, that a general solicitation of the public for employment shall not constitute a solicitation hereunder so long as such general solicitation is not designed to target any employee of the Company.

(d) During the Non-Compete Period, Employee shall not directly or indirectly: (i) interfere with, disrupt, or attempt to disrupt the relationship, contractual or otherwise, between the Company and any current, potential, or prospective customer, vendor, supplier, subcontractor, lessor, lessee, employee, independent contractor, consultant, joint venturer, banker, financier, or investor of the Company, or in any way encourage them to terminate, resign, or otherwise alter their relationship with the Company; or (ii) solicit, call on, suggest, induce, entice away, interfere with, attempt to divert, accept business from or market services or products to, encourage, facilitate, or otherwise benefit from any person, current, potential, or prospective customer, vendor, supplier, subcontractor, lessor, lessee, employee, independent contractor, consultant, joint venturer, banker, financier, or investor of the Company.

(e) Employee and the Company agree that the foregoing covenants are reasonable under the circumstances, necessary to protect the Company's Business and interests, goodwill, confidential information, and other business assets the covenants are intended to protect, and that any breach of such restrictions would cause irreparable injury to the Company. Employee understands that the foregoing restrictions may limit Employee's ability to engage in certain businesses anywhere in the United States and outside the United States during the

Non-Compete Period but acknowledges that Employee will receive sufficiently high remuneration and other benefits from the Company to justify such restrictions. Further, Employee acknowledges that Employee's skills are such that he can be gainfully employed in non-competitive employment, and that the agreement not to compete will not prevent Employee from earning a living. Nevertheless, in the event the terms of this Article 11 shall be determined by any court of competent jurisdiction to be unenforceable by reason of its extending for too great a period of time or over too great a geographical area or by reason of its being too extensive in any other respect, it will be interpreted to extend only over the maximum period of time for which it may be enforceable, over the maximum geographical area as to which it may be enforceable, or to the maximum extent in all other respects as to which it may be enforceable, all as determined by such court in such action.

(f) Employee hereby represents to the Company that he has read and understands, and agrees to be bound by, the terms of this Article 11. Employee acknowledges that the geographic scope and duration of the covenants contained in this Article 11 are the result of arm's-length bargaining and are fair and reasonable in light of (i) the nature and wide geographic scope of the Company's operations of, and in, the Business, (ii) Employee's level of control over and contact with the Company's operations of, and in, the Business in all locales in which it is conducted, (iii) the geographic breadth in which the Company conducts the Business and (iv) the amount of consideration (including confidential information and trade secrets) that Employee is receiving from the Company.

(g) In consideration of the Company's promises herein, during the Non-Compete Period, Employee promises to disclose to the Company any employment, consulting, or other service relationship that Employee enters into after the termination of Employee's employment with the Company for any reason. Such disclosure shall be made within seven business days after Employee enters into such employment, consulting or other service relationship. Employee expressly consents to and authorizes the Company to disclose both the existence and terms of this Agreement to any future employer or recipient of Employee's services and to take any steps the Company deems necessary to enforce this Agreement.

ARTICLE 12
NONDISCLOSURE OF CONFIDENTIAL AND PROPRIETARY INFORMATION

Section 12.01. *Nondisclosure of Confidential and Proprietary Information.* (a) Except in connection with the faithful performance of Employee's duties for the Company or pursuant to Section 12.01(c) or (e), Employee shall, in perpetuity, maintain in confidence and shall not directly, indirectly or otherwise, (i) use, disseminate, disclose or publish, or use for his benefit or the benefit of any person, firm, corporation or other entity, any (A) confidential or proprietary information or

trade secrets of or relating to the Company (including, without limitation, intellectual property in the form of patents, trademarks and copyrights and applications therefor, ideas, inventions, works, discoveries, improvements, information, documents, formulae, practices, processes, methods, developments, source code, modifications, technology, techniques, data, programs, other know-how or materials, in each case, that are confidential and/or proprietary and owned, developed or possessed by the Company, whether in tangible or intangible form) or (B) confidential or proprietary information with respect to the Company's operations, processes, products, inventions, business practices, strategies, business plans, finances, principals, vendors, suppliers, customers, bankers, financiers, investors, potential customers, marketing methods, costs, prices, contractual relationships, regulatory status, prospects and compensation paid to employees or other terms of employment or (ii) deliver to any person, firm, corporation or other entity any document, record, notebook, computer program or similar repository of or containing any such confidential or proprietary information or trade secrets. The parties hereby stipulate and agree that as between them the foregoing matters are important, material and confidential proprietary information and trade secrets and materially affect the successful conduct of the businesses of the Company (and any successor or assignee of the Company).

(b)Upon the termination of Employee's employment with the Company for any reason, Employee will promptly deliver to the Company all correspondence, drawings, manuals, letters, notes, notebooks, reports, programs, plans, proposals, financial documents and electronically stored information, in each case, that are confidential or proprietary to the Company, or any other confidential or proprietary documents (including electronically stored information) concerning the Company's customers, business plans, strategies, products or processes.

(c)Employee may respond to a lawful and valid subpoena or other legal process relating to the Business of the Company or the performance of his duties on behalf of the Company but shall (i) give the Company prompt notice thereof, (ii) make available to the Company and its counsel the documents and other information sought that are not subject to a binding confidentiality agreement and (iii) assist such counsel at Company's expense in resisting or otherwise responding to such process.

(d)As used in this Article 12 and Article 13, the term "**Company**" shall include the Company and its Affiliates and subsidiaries.

(e)Nothing in this Agreement shall prohibit Employee from (i) disclosing information and documents when required by law, subpoena, court order or legal process, (ii) disclosing information and documents to his immediate family members or, for the purpose of securing legal or tax advice, attorney or tax adviser (provided that the persons to whom such disclosures are made shall be informed of their obligation to maintain the strict confidentiality of any

information provided to them), (iii) disclosing the post-employment restrictions in this Agreement in confidence to any potential new employer or person or entity to whom he may provide consulting services, or (iv) retaining, at any time, his personal correspondence and rolodex or address book and documents related to his own personal benefits, entitlements and obligations.

ARTICLE 13
INVENTIONS

Section 13.01. *Inventions*. All rights to discoveries, inventions, improvements and innovations (including all data and records pertaining thereto) related to the Business of the Company, whether or not patentable, copyrightable, registrable as a trademark, or reduced to writing, that Employee may discover, invent or originate during the period of his employment with the Company, either alone or with others and whether or not during working hours or by the use of the facilities of the Company ("**Inventions**"), shall be the exclusive property of the Company. Employee shall promptly disclose all Inventions to the Company, shall execute at the request of the Company any assignments or other documents the Company may deem reasonably necessary to protect or perfect its rights therein, and shall assist the Company, upon reasonable request and at the Company's expense, in obtaining, defending and enforcing the Company's rights therein. Employee hereby appoints the Company as his attorney-in-fact to execute on his behalf any assignments or other documents reasonably deemed necessary by the Company to protect or perfect its rights to any Inventions.

ARTICLE 14
INJUNCTIVE RELIEF

Section 14.01. *Injunctive Relief*. It is recognized and acknowledged by Employee that a breach of the covenants contained in Articles 11, 12, 13 and 15 will cause irreparable damage to Company and its Affiliates and their goodwill, the exact amount of which will be difficult or impossible to ascertain, and that the remedies at law for any such breach will be inadequate. Accordingly, Employee agrees that in the event of a breach of any of the covenants contained in Articles 11, 12, 13 and 15, in addition to any other remedy which may be available at law or in equity, the Company will be entitled to specific performance and injunctive relief. It is also agreed that seeking or obtaining such equitable or injunctive relief shall not waive a Party's ability to compel or seek arbitration under the terms of this Agreement.

ARTICLE 15
NON-DISPARAGEMENT

Section 15.01. *Non-Disparagement.* During Employee's employment with the Company and following termination of his employment with the Company for any reason, (a) Employee agrees not to disparage in any material respect the Company, its Affiliates or subsidiaries, any of their products or practices, or any of their directors, officers, agents, representatives, members, partners or stockholders, either orally or in writing, and (b) the Company agrees that it and its Affiliates and subsidiaries will (i) not make any formal statements that disparage in any material respect Employee and (ii) use commercially reasonable efforts to advise its directors and officers not to disparage in any material respect Employee.

ARTICLE 16
GENERAL

Section 16.01. *Survivorship.* The respective rights and obligations of the parties hereunder shall survive any termination of this Agreement to the extent necessary for the intended preservation of such rights and obligations.

Section 16.02. *Arbitration.* Any dispute or controversy arising under or in connection with this Agreement shall be settled exclusively by arbitration, conducted before an arbitrator in Houston, Texas in accordance with the National Rules for the Resolution of Employment Disputes of the American Arbitration Association then in effect, except that the Company shall be entitled to seek a restraining order, injunction, or other equitable relief, and expedited discovery necessary for the proceedings to obtain said equitable or injunctive relief, in order to prevent or cease any violation or continuation of any violation of the provisions of Articles 11, 12, 13 or 15 of this Agreement, and to obtain specific performance of said Articles. Employee hereby consents that such restraining order or injunction may be granted without requiring the Company to post a bond larger than $500. Employee also agrees that waiver shall not be a defense to Company's invocation of the Agreement's arbitration clause subsequent to any proceeding to obtain the equitable or injunctive relief described herein. Further, for purposes of obtaining said equitable and injunctive relief, Employee consents to the personal jurisdiction and venue of any Texas State court or United States court located in Harris County, Texas. Judgment may be entered on the arbitration award in any court having jurisdiction. Only individuals who are on the AAA register of arbitrators shall be selected as an arbitrator. Within 20 days of the conclusion of the arbitration hearing, the arbitrator(s) shall prepare written findings of fact and conclusions of law. It is mutually agreed that the written decision of the arbitrator(s) shall be valid, binding, final and non-appealable; provided however, that the parties hereto agree that the arbitrator shall not be empowered to award punitive damages against any party to such arbitration. The Company shall bear all administrative fees and expenses of the arbitration and each party shall bear its

own counsel fees and expenses except as otherwise provided in this paragraph. If Employee makes a claim against the Company relating to the performance of, or the rights and obligations of, the Company arising under, relating to or in connection with this Agreement (a "**Covered Claim by the Employee**"), the arbitrators shall award Employee his reasonable legal fees and expenses if Employee prevails on one material Covered Claim by the Employee (as determined by the arbitrator). If a claim is made by the Company against Employee relating to the performance of, or the rights and obligations of, Employee arising under, relating to or in connection with this Agreement (a "**Covered Claim by the Company**"), the arbitrators shall award Employee his reasonable legal fees and expenses; *provided* that if such Covered Claim by the Company relates to Employee's performance or obligations under Articles 11, 12, 13 or 15, the arbitrators shall award Employee his legal fees and expenses only if the Company does not prevail on any Covered Claim by the Company relating to any such Section (as determined by the arbitrator). Any reimbursement of reasonable legal fees and expenses required under this Section 16.02 and any reimbursement of expenses included in the Accrued Obligations payable to Employee under Article 6 shall be made not later than the close of Employee's taxable year following the taxable year in which Employee incurs the expense; *provided*, *however*, that, upon Employee's termination of employment with the Company, in no event shall any additional reimbursement be made prior to the date that is six months after the date of Employee's termination of employment to the extent such payment delay is required under Section 409A(a)(2)(B)(i) of the Code. In no event shall any reimbursement be made to Employee for such fees and expenses incurred after the date that is 10 years after the date of Employee's termination of employment with the Company.

Section 16.03. *Payment Obligations Absolute.* The Company's obligation to pay Employee the amounts and to make the arrangements provided herein shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which the Company (including its Affiliates and subsidiaries) may have against him or anyone else. All amounts payable by the Company shall be paid without notice or demand. Employee shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Agreement, and the obtaining of any such other employment shall in no event effect any reduction of the Company's obligations to make (or cause to be made) the payments and arrangements required to be made under this Agreement.

Section 16.04. *Successors.* This Agreement shall be binding upon and inure to the benefit of the Company and any successor of the Company, by merger or otherwise. This Agreement shall also be binding upon and inure to the benefit of Employee and his estate. If Employee shall die prior to full payment of amounts due pursuant to this Agreement, such amounts shall be payable pursuant to the terms of this Agreement to his estate.

Section 16.05. *Severability.* Any provision in this Agreement which is prohibited or unenforceable in any jurisdiction by reason of applicable law shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating or affecting the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 16.06. *Non-alienation.* Employee shall not have any right to pledge, hypothecate, anticipate or assign this Agreement or the rights hereunder, except by will or the laws of descent and distribution.

Section 16.07. *Notices.* Any notices or other communications provided for in this Agreement shall be sufficient if in writing. In the case of Employee, such notices or communications shall be effectively delivered if hand-delivered to Employee at his principal place of employment or if sent by registered or certified mail to Employee at the last address he has filed with the Company. In the case of the Company, such notices or communications shall be effectively delivered if sent by registered or certified mail to the Company at its principal Employee offices.

Section 16.08. *Controlling Law and Waiver of Jury Trial.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Texas. With respect to any claim or dispute related to or arising under this Agreement, Employee and the Company hereby consent to the exclusive jurisdiction, forum and venue of the state and federal courts located in Harris County, Texas. Notwithstanding the foregoing, Section 4.01 and the transfer restrictions set forth in Annex II of the Prior Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware. Furthermore, with respect to any claim or dispute related to or arising under Section 4.01 and the transfer restrictions set forth in Annex II of the Prior Agreement, Employee and the Company hereby consent to the exclusive jurisdiction, forum and venue of the Court of Chancery of the State of Delaware. Each of the parties hereto hereby irrevocably waives any and all right to trial by jury in any legal proceeding arising out of or related to this Agreement or the transactions contemplated hereby.

Section 16.09. *Release and Delayed Payment Restriction.* (a) As a condition to the receipt of any benefit under Article 5 hereof (except in the case of the termination of Employee's employment with the Company by reason of Employee's death or Disability and except for the Accrued Obligations), Employee shall first execute a release in the form attached hereto as Exhibit A (with such changes therein as the Company may reasonably require to reflect changes in applicable law and the circumstances relating to the termination of Employee's employment), releasing the Company and certain other persons and entities from certain claims and other liabilities.

(b)The release described in Section 16.09(a) hereof must be effective and irrevocable within 55 days after the date of the termination of Employee's

employment with the Company. Notwithstanding any provision in this Agreement to the contrary, if the payment of any amount or benefit under this Agreement would be subject to additional taxes and interest under Section 409A of the Code because the timing of such payment is not delayed as provided in Section 409A(a)(2)(B)(i) of the Code and the regulations thereunder, then any such payment or benefit that Employee would otherwise be entitled to during the first six months following the date of Employee's termination of employment shall be accumulated and paid or provided, as applicable, on the date that is six months after the date of Employee's termination of employment (or if such date does not fall on a business day of the Company, the next following business day of the Company), or such earlier date upon which such amount can be paid or provided under Section 409A of the Code without being subject to such additional taxes and interest. If this Section 16.09(b) becomes applicable such that the payment of any amount is delayed, any payments that are so delayed shall accrue interest on a non-compounded basis, from the date such payment would have been made had this Section 16.09(b) not applied to the actual date of payment, at the prime rate of interest announced by JPMorgan Chase Bank (or any successor thereto) at its principal office in New York on the date of Employee's termination of employment (or the first business day following such date if such termination does not occur on a business day) and shall be paid in a lump sum on the actual date of payment of the delayed payment amount. Employee hereby agrees to be bound by the Company's determination of its "specified employees" (as such term is defined in Section 409A of the Code) in accordance with any of the methods permitted under the regulations issued under Section 409A of the Code.

Section 16.10. *Full Settlement.* If Employee is entitled to and receives the benefits provided hereunder, performance of the obligations of the Company hereunder will constitute full settlement of all claims that Employee might otherwise assert against the Company on account of his termination of employment.

Section 16.11. *Unfunded Obligation.* The obligation to pay amounts under this Agreement is an unfunded obligation of the Company, and no such obligation shall create a trust or be deemed to be secured by any pledge or encumbrance on any property of the Company.

Section 16.12. *No Right to Continued Employment.* Employee and the Company recognize and agree that subject to the terms of this Agreement (including the notice provisions of Section 7.02), (i) the Company may terminate Employee's employment at any time, for any reason or no reason at all and (ii) Employee may terminate his employment at any time, for any reason or no reason at all.

Section 16.13. *Withholding of Taxes and Other Employee Deductions.* The Company may withhold from any benefits and payments made pursuant to this Agreement (whether actually or constructively made to Employee or treated as

included in Employee's income under Section 409A of the Code) all federal, state, city, foreign and other applicable taxes and withholdings as may be required pursuant to any law or governmental regulation or ruling and all other customary deductions made with respect to the Company's employees generally.

Section 16.14. *Number and Gender.* Wherever appropriate herein, words used in the singular shall include the plural and the plural shall include the singular. The masculine gender where appearing herein shall be deemed to include the feminine gender.

Section 16.15. *Entire Agreement.* Except as provided in Section 2.02, this Agreement, including the Exhibit attached hereto, constitutes the entire agreement of the parties with regard to the subject matter hereof and supersedes any and all prior understandings, agreements or correspondence between the parties. Any modification of this Agreement will be effective only if it is in writing and signed by the party to be charged.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the date and year first written above.

EMPLOYEE

By: /s/ James W. Farnsworth

Name: James W. Farnsworth

Title: Chief Exploration Officer and Executive Vice President, Exploration and New Ventures

COBALT INTERNATIONAL ENERGY, INC.

By: /s/ Joseph H. Bryant

Name: Joseph H. Bryant

Title: Chairman and Chief Executive Officer

EXHIBIT A

FORM OF RELEASE

For and in consideration of certain payments and other benefits due to [•] ("**Employee**") pursuant to the Employment Agreement (the "**Employment Agreement**") dated as of [•], 20 , between Cobalt International Energy, Inc., (the "**Company**") and Employee, and for other good and valuable consideration, Employee hereby agrees, for Employee, Employee's spouse and child or children (if any), Employee's heirs, beneficiaries, devisees, executors, administrators, attorneys, personal representatives, successors and assigns, to forever release, discharge and covenant not to sue the Company and its divisions, Affiliates, subsidiaries, parents, branches, predecessors, successors, assigns, and, with respect to such entities, their officers, directors, trustees, employees, agents, shareholders, administrators, general or limited partners, members, representatives, attorneys, insurers and fiduciaries, past, present and future (the "**Released Parties**") from any and all claims of any kind arising out of, or related to, his employment with the Company, its Affiliates or subsidiaries (collectively, with the Company, the "**Affiliated Entities**") or Employee's separation from employment with the Affiliated Entities, which Employee now has or may have against the Released Parties, whether known or unknown to Employee, by reason of facts which have occurred on or prior to the date that Employee has signed this Release. Such released claims include, without limitation, any and all claims relating to the foregoing under federal, state or local laws pertaining to employment, including, without limitation, the Age Discrimination in Employment Act, Title VII of the Civil Rights Act of 1964, as amended, 42 U.S.C. Section 2000e *et seq.*, the Fair Labor Standards Act, as amended, 29 U.S.C. Section 201 *et seq.*, the Americans with Disabilities Act, as amended, 42 U.S.C. Section 12101 *et seq.* the Reconstruction Era Civil Rights Act, as amended, 42 U.S.C. Section 1981 *et seq.*, the Rehabilitation Act of 1973, as amended, 29 U.S.C. Section 701 *et seq.*, the Family and Medical Leave Act of 1992, 29 U.S.C. Section 2601 *et seq.*, and any and all state or local laws regarding employment discrimination, the payment of wages and/or federal, state or local laws of any type or description regarding employment, including but not limited to any claims arising from or derivative of Employee's employment with the Affiliated Entities, as well as any and all such claims under state contract or tort law. By signing this Release, Employee is bound by it. Anyone who succeeds to Employee's rights and responsibilities, such as heirs or the executor of Employee's estate, is also bound by this Release. This Release also applies to any claims brought by any person or agency or class action under which Employee may have a right or benefit. Notwithstanding this release of liability, nothing in this Release prevents Employee from filing any non-legally waivable claim (including a challenge to the validity of this Release) with the Equal Employment Opportunity Commission (the "**EEOC**") or comparable state or local agency or participating in any investigation or proceeding conducted by the EEOC or comparable state or local agency; however, Employee understands and agrees that Employee is waiving

any and all rights to recover any monetary or personal relief or recovery as a result of such EEOC or comparable state or local agency proceeding or subsequent legal actions.

Protections under Older Workers Benefits Protection Act. Employee has read this Release carefully, and acknowledges that Employee fully understands its terms. Further, Employee acknowledges that Employee has been given at least 21 days to consider all of its terms and has been and is hereby advised to consult with an attorney and any other advisors of Employee's choice prior to executing this Release, and Employee fully understands that by signing below Employee is knowingly and voluntarily giving up any right which Employee may have to sue or bring any other claims against the Released Parties, including any rights and claims under the Age Discrimination in Employment Act. Employee also understands that Employee has a period of seven (7) days after signing this Release within which to revoke his agreement, and that neither the Company nor any other person is obligated to make any payments or provide any other benefits to Employee pursuant to the Agreement until eight days have passed since Employee's signing of this Release without Employee's signature having been revoked other than any accrued obligations or other benefits payable pursuant to the terms of the Company's normal payroll practices or employee benefit plans. Finally, Employee expressly represents that he has not been forced or pressured in any manner whatsoever to sign this Release, and Employee agrees to all of its terms knowingly and voluntarily.

Notwithstanding anything else herein to the contrary, this Release shall not affect: (i) the Company's obligations under any compensation or employee benefit plan, program or arrangement (including, without limitation, obligations to Employee under the Employment Agreement or any stock option, stock award or agreements or obligations under any pension, deferred compensation or retention plan) provided by the Affiliated Entities where Employee's compensation or benefits are intended to continue or Employee is to be provided with compensation or benefits, in accordance with the express written terms of such plan, program or arrangement, beyond the date of Employee's termination and (ii) rights to indemnification Employee may have under (A) applicable law, (B) any other agreement between Employee and a Released Party and (C) as an insured under any director's and officer's liability insurance policy now or previously in force. This Release also shall not affect any prospective claims arising after the date of its execution.

This Release is final and binding and may not be changed or modified except in a writing signed by both parties.

Date

James W. Farnsworth
Chief Exploration Officer and Executive Vice President, Exploration and New Ventures

Cobalt International Energy, Inc.

Date:

By:

Name:

Title:

Exhibit 10.35

EMPLOYMENT AGREEMENT

dated as of November 3, 2014,

between

COBALT INTERNATIONAL ENERGY, INC.,
(*the Company*)

and

JAMES H. PAINTER,
(*Employee*)

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EMPLOYMENT AGREEMENT

This EMPLOYMENT AGREEMENT (this "**Agreement**") dated as of November 3, 2014 ("**Effective Date**"), is made by and between COBALT INTERNATIONAL ENERGY, INC., a Delaware corporation (the "**Company**"), and James H. Painter, ("**Employee**") (jointly referred to herein as the "Parties").

RECITALS

WHEREAS, the Company and Employee are party to an employment agreement dated October 23, 2009 (the "**Prior Agreement**") that is scheduled to expire on December 21, 2014;

WHEREAS, the Compensation Committee of the Board of Directors of the Company has approved the Company's entering into this Agreement with Employee to pay for Employee's services and in exchange for the promises and covenants herein;

WHEREAS, this Agreement shall supersede the Prior Agreement except as set forth in Section 2.02 and 4.01 herein.

WHEREAS, during the course of Employee's employment, Company has provided and will continue to provide Employee with non-public, confidential, and proprietary information developed by the Company relating to the Company's Business, interests, methods, business plans, finances, and operations;

WHEREAS, the Board of Directors of the Company (the "**Board**") and its designated committee(s) intends to encourage Employee's continued service to the Company, Employee's participation in the Company's succession planning for Employee's position, and the development of the Company's short and long-term Business (as defined in Section 11.01(a) of this Agreement), interests, goals, and goodwill;

WHEREAS, the Company invests considerable resources in building partner, vendor, supplier, banking, financier, and investor relationships, and developing strategic plans and goodwill in the energy industry, not only by paying for Employee's services and investing in the development of Employee, but also by investing in research and development, and exploration techniques and technologies which are non-public, confidential, and proprietary;

WHEREAS, the Company and Employee acknowledge that the breadth and scope of the Company's operations covers a global territory due to the nature of the oil and natural gas exploration business, the Company's operations and Business, exploration goals and strategies, which Employee has had access to and will continue to have access to in order to perform Employee's duties; and

WHEREAS, the Company and Employee agree and understand that this Agreement and the mutual promises and covenants herein are intended to, and do, advance the interests of the Company, including but not limited to the Company's goodwill, growth, strategy, and development, and also the interests of Employee, and are also reasonable and necessary to protect Company's Business, confidential and proprietary information, and goodwill.

AGREEMENT

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration set forth herein, the sufficiency of which is acknowledged by the Parties, the Company and Employee agree as follows:

ARTICLE 1
DEFINITIONS

Section 1.01. *Definitions.*

"**Accrued Obligations**" shall mean Employee's base salary through the Date of Termination of Employment not theretofore paid, any expenses owed to Employee under the Company's expense reimbursement policy as in effect from time to time, any accrued vacation pay owed to Employee pursuant to the Company's vacation policy as in effect from time to time, any earned but unpaid annual performance bonus with respect to a calendar year that has ended on or before the Date of Termination of Employment (it being understood that a bonus will not be considered to have been unearned merely because Employee has not remained employed through the payment date so long as Employee has remained employed through the end of the calendar year that has ended on or before the Date of Termination of Employment), any amount accrued and arising from Employee's participation in, or benefits accrued under, any employee benefit plans, programs or arrangements maintained by the Company which amounts shall be payable in accordance with the terms and conditions of such employee benefit plans, programs or arrangements, and such other or additional benefits as may be, or become, due to Employee under the applicable terms of applicable plans, programs, agreements, corporate governance documents and other arrangements of the Company and its Affiliates and subsidiaries.

"**Affiliate**" shall mean any entity that owns or controls, is owned or controlled by, or is under common control with, the Company. An entity is deemed to control another if it owns, directly or indirectly, at least 50% of: (i) the shares entitled to vote at a general election of directors of such other entity, or (ii) the voting interest in such other entity if such entity does not have either shares or directors.

"**Agreement Termination Date**" shall mean the last day of the Employment Term.

"**Annual Bonus**" shall have the meaning assigned to such term in Section 6.02.

"**Annualized Base Salary**" shall mean an amount equal to the greater of:

Employee's annualized base salary at the rate in effect on the date of his Involuntary Termination or termination by reason of death or Disability, as applicable;

Employee's annualized base salary at the rate in effect 90 days prior to the date of his Involuntary Termination or termination by reason of death or Disability, as applicable; or

Employee's annualized base salary at the rate in effect immediately prior to a Change in Control if, on the date upon which such Change in Control occurs or within two years thereafter, Employee's employment shall be subject to an Involuntary Termination or be terminated by reason of death or Disability.

Annualized Base Salary shall not include any bonuses, incentive compensation, or equity-based compensation.

"**Base Salary**" shall have the meaning assigned to such term in Section 6.01.

"**Board**" shall have the meaning assigned to such term in the Recitals.

"**Cause**" shall mean:

(i) The willful failure of Employee to substantially perform Employee's duties as an employee of the Company (other than any such failure resulting from Employee's physical or mental incapacity),

(ii) Employee's having engaged in willful misconduct, gross negligence or a breach of fiduciary duty that results in material and demonstrable harm to the Company or any of its Affiliates,

(iii) Employee's willful and material breach of this Agreement (as amended from time to time) that results in material and demonstrable harm to the Company or any of its Affiliates,

(iv) Employee's having been convicted of, or having entered a plea bargain or settlement admitting guilt or the imposition of unadjudicated probation for, any felony under the laws of the United States, any state or the District of Columbia, where such felony involves

moral turpitude or where, as a result of such felony, the continued employment of Employee would have, or would reasonably be expected to have, a material adverse impact on the Company's or any of its Affiliates' reputations,

(v) Employee's having been the subject of any order, judicial or administrative, obtained or issued by the Securities and Exchange Commission, for any securities violation involving fraud including, for example, any such order consented to by Employee in which findings of facts or any legal conclusions establishing liability are neither admitted nor denied,

(vi) Employee's unlawful use (including being under the influence of) or possession of illegal drugs on the Company's or any of its Affiliate's premises or while performing Employee's duties and responsibilities as an employee of the Company, or

(vii) Employee's commission of an act of fraud, embezzlement, or misappropriation, in each case, against the Company or any of its Affiliates.

The provisions in this Agreement for termination (for Cause or otherwise) are set forth in more detail in Section 7.02, including provisions regarding notice and opportunity to cure.

For purposes of this definition, no act, or failure to act, on the part of Employee shall be considered "willful" unless it is done, or omitted to be done, by Employee in bad faith or without reasonable belief that Employee's action or omission was in the best interests of the Company. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer of the Company (other than Employee if he is serving in such capacity) or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by Employee in good faith and in the best interests of the Company.

(a) "**Change in Control**" means the occurrence of any one or more of the following events:

(i) any "person" (as defined in Section 13(d) of the Securities Exchange Act of 1934 (the "**Act**")), other than an employee benefit plan or trust maintained by the Company, becomes the "beneficial owner" (as defined in Rule 13d-3 under the Act), directly or indirectly, of securities of the Company representing more than 50% of the combined voting power of the Company's outstanding securities entitled to vote generally in the election of directors;

(ii) at any time during a period of 12 consecutive months, individuals who at the beginning of such period constituted the Board and any new member of the Board whose election or nomination for election was approved by a vote of at least a majority of the directors then still in office who either were directors at the beginning of such period or whose election or nomination for election was so approved, cease for any reason to constitute a majority of members of the Board; or

(iii) the consummation of (A) a merger or consolidation of the Company or any of its subsidiaries with any other corporation or entity, other than a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or being converted into voting securities of the surviving entity or, if applicable, the ultimate parent thereof) at least 50% of the combined voting power and total fair market value of the securities of the Company or such surviving entity or parent outstanding immediately after such merger or consolidation, or (B) any sale, lease, exchange or other transfer to any Person (other than an affiliate (as defined in the Company Long Term Incentive Plan)) of assets of the Company and/or any of its subsidiaries, in one transaction or a series of related transactions, having an aggregate fair market value of more than 50% of the fair market value of the Company and its subsidiaries (the "**Company Value**") immediately prior to such transaction(s), but only to the extent that, in connection with such transaction(s) or within a reasonable period thereafter, the Company's stockholders receive distributions of cash and/or assets having a fair market value that is greater than 50% of the Company Value immediately prior to such transaction(s).

Notwithstanding the foregoing, in no event shall a Change in Control be deemed to have occurred with respect to Employee if Employee is part of a "group" within the meaning of Section 13(d)(3) of the Act that consummates the Change in Control transaction. In addition, for purposes of the definition of Change in Control, a person engaged in business as an underwriter of securities shall not be deemed to be the beneficial owner of, or to beneficially own, any securities acquired through such person's participation in good faith in a firm commitment underwriting until the expiration of 40 days after the date of such acquisition.

"**Code**" shall mean the Internal Revenue Code of 1986, as amended.

"**Date of Termination of Employment**" shall mean (i) if Employee's employment with the Company is terminated by his death, the date of Employee's death, or (ii) if Employee's employment with the Company is terminated for any reason whatsoever other than Employee's death, the earlier of the date indicated in the Notice of Termination of Employment or the date specified by the Company pursuant to Section 7.02.

“**Disability**” shall mean, at any time the Company or any Affiliate sponsors a long-term disability plan that covers Employee and other employees of the Company, “disability” as defined in such long-term disability plan for the purpose of determining a participant’s eligibility for benefits; *provided*, *however*, if the long-term disability plan contains multiple definitions of disability, then “Disability” shall refer to that definition of disability which, if Employee qualified for such disability benefits, would provide coverage for the longest period of time. The determination of whether Employee has a Disability shall be made by the person or persons required to make final disability determinations under the long-term disability plan. At any time the Company or any Affiliate does not sponsor such a long-term disability plan, Disability shall mean Employee’s inability to perform, with or without reasonable accommodation, the essential functions of his position with the Company for a total of three months during any six-month period as a result of incapacity due to mental or physical illness, as determined by a physician selected by the Company or its insurers and acceptable to Employee or Employee’s legal representative, such agreement as to acceptability not to be unreasonably withheld or delayed. Any refusal by Employee to submit to a medical examination for the purpose of determining Disability shall be deemed to constitute conclusive evidence of Employee’s Disability.

“**Effective Date**” shall have the meaning assigned to such term in the preamble of this Agreement.

“**Employment Term**” shall have the meaning assigned to such term in Section 2.01.

“**Good Reason**” shall mean the occurrence of any of the following events: (i) a material diminution in Employee’s base salary or (ii) relocation of the geographic location of Employee’s principal place of employment by more than 75 miles from Houston, Texas.

Notwithstanding the preceding provisions of this definition or any other provision in this Agreement to the contrary, any assertion by Employee of a termination of employment for “Good Reason” shall not be effective unless all of the following conditions precedent are satisfied: (A) the condition described in clauses (i) or (ii) of this definition giving rise to Employee’s termination of employment must have arisen without Employee’s consent; (B) Employee must provide written notice to the Company of such condition in accordance with Section 16.07 within 45 days of the initial existence of the condition; (C) the condition specified in such notice must remain uncorrected for 30 days after receipt of such notice by the Company; and (D) the date of Employee’s termination of employment for Good Reason must occur within 90 days after the initial existence of the condition specified in such notice.

“**Inventions**” shall have the meaning assigned to such term in Article 13.

“**Involuntary Termination**” shall mean any termination of Employee’s employment with the Company (i) by the Company without Cause or (ii) by Employee for Good Reason. “Involuntary Termination” shall not include a termination of Employee’s employment with the Company for any other reason whatsoever, including, without limitation: (A) by the Company for Cause, (B) by Employee without Good Reason, or (C) as a result of Employee’s death or Disability.

“**Long Term Incentive Plan**” shall mean the Cobalt International Energy, Inc. Long Term Incentive Plan as in effect from time to time or any successor plan thereto.

“**Non-Compete Period**” shall have the meaning assigned to such term in Section 11.01(a).

“**Notice of Non-Renewal**” shall have the meaning assigned to such term in Section 7.04.

“**Notice of Termination of Employment**” shall have the meaning assigned to such term in Section 7.02.

“**Prior Agreement**” shall have the meaning assigned to such term in the Recitals of this Agreement.

“**Pro Rata Bonus**” shall mean an amount equal to the product of (i) the actual annual bonus Employee would have been entitled to receive, based on the Company’s actual performance through the end of the calendar year in which Employee’s termination of employment with the Company occurred, determined as if he had continued his employment with the Company through the end of such calendar year and (ii) a fraction, the numerator of which is the number of days during the calendar year through the date of Employee’s termination of employment with the Company and the denominator of which is 365.

“**Pro Rata Bonus Payment Date**” shall mean, with respect to a Pro Rata Bonus for a particular calendar year, the date on which annual bonuses for such calendar year are generally paid to employees of the Company who have not terminated employment with the Company, but in no event earlier than January 1 of the year following such calendar year nor later than December 31 of the year following such calendar year.

“**Renewal Date**” shall have the meaning assigned to such term in Section 2.01.

“**Separation from Service**” means, with respect to Employee, the (i) cessation of all services performed by Employee for the Company or (ii) permanent decrease in the level of services performed by Employee for the Company (whether as an employee or as an independent contractor) to no more

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than 20 percent of the average level of services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Company, if Employee has been providing services to the Company for less than 36 months).

"**Severance Amount**" shall mean (i) if Employee incurs an Involuntary Termination prior to a Change in Control or on or after the second anniversary of the Change in Control (to the extent applicable), 100% of Annualized Base Salary and (ii) if Employee incurs an Involuntary Termination on the date of the Change in Control or prior to the second anniversary of the Change in Control, 100% of Annualized Base Salary.

"**Transfer**" shall have the meaning assigned to such term in Section 9.01.

ARTICLE 2
EFFECTIVENESS; TERM OF AGREEMENT;
TERMINATION OF PRIOR AGREEMENT

Section 2.01. *Effectiveness; Term of Agreement.* This Agreement is effective as of the Effective Date, referenced in the preamble of this Agreement, and shall continue until December 31, 2016, unless terminated earlier pursuant to Article 7 of this Agreement; *provided* that, on December 31, 2016 and each annual anniversary thereafter (such date and each annual anniversary thereof, a "**Renewal Date**"), this Agreement shall automatically extend, upon the same terms and conditions, for successive periods of one year, unless either party provides written notice of its intention not to extend the term of the Agreement at least 30 days prior to the applicable Renewal Date. The period during which Employee is employed by the Company is referred to as the "**Employment Term**". The covenants contained in Articles 11, 12, 13, 14, and 15 shall remain enforceable past the Employment Term, as specifically set forth in those Articles.

Section 2.02. *Termination of Prior Agreement; Continuing Effectiveness of Transfer Restrictions.* The Prior Agreement shall be of no further force or effect upon the Effective Date of this Agreement, except for the transfer restrictions set forth in Annex II of the Prior Agreement, which shall remain in full force and effect pursuant to the terms thereof and are incorporated herein by reference. By entering into this Agreement, Employee hereby agrees to continue to be bound by the transfer restrictions set forth in Annex II of the Prior Agreement.

ARTICLE 3
POSITIONS AND DUTIES

Section 3.01. *Employment; Positions.* Employee shall be employed as Executive Vice President, Execution and Appraisal of the Company. The

Company may subsequently assign Employee to a different position with the Company or any Affiliate of the Company or modify Employee's duties, responsibilities and reporting relationship; *provided* that any assignment of a new position or modification of Employee's duties, responsibilities or reporting relationship shall be subject to Employee's consent, which consent may not be unreasonably withheld so long as the new position reasonably relates to Employee's experience and existing position. Moreover, the Company may assign this Agreement and Employee's employment to any Affiliate of the Company.

Section 3.02. *Duties and Services*. Employee agrees to serve in the position(s) assigned pursuant to Section 3.02 and to perform diligently and to the best of Employee's abilities the duties and services pertaining to such position(s), as well as such additional duties and services that the Company may reasonably direct Employee. Employee's employment shall also be subject to the policies maintained and established by the Company that are of general applicability to the Company's employees.

Section 3.03. *Succession Planning*. Employee agrees that Employee's duties and services to the Company include participating in good faith in the Company's succession planning for Employee's position, as directed by the Company's Chief Executive Officer. Employee's succession planning responsibilities may include, but are not limited to, Employee's collaboration with the Company in identifying, evaluating and developing a successor for Employee's position, as well as facilitating a smooth transition to such successor.

Section 3.04. *Other Interests*. Employee agrees, during the period of Employee's employment by the Company, to devote substantially all of Employee's business time, energy and best efforts to the business and affairs of the Company and its Affiliates. Notwithstanding the foregoing, the parties acknowledge and agree that Employee may (a) engage in and manage Employee's passive personal investments, (b) engage in charitable and civic activities and (c) serve on corporate boards and committees of for-profit companies, so long as such activities do not conflict with the Business and affairs of the Company and its Affiliates or interfere with Employee's performance of Employee's duties.

ARTICLE 4
CERTAIN EMPLOYEE REPRESENTATIONS AND AGREEMENTS;
SPECIAL EQUITY GRANTS

Section 4.01. *Transfer Restrictions*. Employee agrees that Employee shall remain bound by the transfer restrictions set forth in Annex II to the Prior Agreement, which are incorporated herein by reference.

Section 4.02. *Life Insurance*. This Agreement constitutes written notice to Employee that (a) the Company or an Affiliate may insure Employee's life, (b) the

Company or an Affiliate shall have the right to determine the amount of insurance and the type of policies, and (c) the Company or an Affiliate will be the beneficiaries of any proceeds payable under such policies upon the death of Employee. Employee hereby irrevocably consents to being insured under the policies described in the preceding sentence and to the coverage under such policies continuing after the termination of this Agreement and/or Employee's termination of employment with the Company and its Affiliates. Employee agrees and acknowledges that Employee shall not have the right to designate the beneficiary or beneficiaries of the death benefit payable pursuant to such policies, and neither Employee nor any other person claiming through Employee shall have any interest in such policies. Employee shall (i) furnish any and all information reasonably requested by the Company, any Affiliate or the insurer to facilitate the issuance of the life insurance policy or policies described in this paragraph or any adjustment to any such policy, and (ii) take such physical examinations as the Company, any Affiliate or the insurer deems necessary. Employee shall incur no financial obligation by executing any required document pursuant to this Section 4.02, and shall have no interest in any such policy.

Section 4.03. *Equity. Grant In Connection With Execution of This Agreement.* In consideration for the promises and covenants contained in this Agreement, including those promises and covenants contained in Articles 11 and 12, Employee shall receive on January 15, 2015 and on January 15, 2016, an equity award granted pursuant to the terms of the Company's Long Term Incentive Plan. Each award shall have a target value of $2,000,000 and shall be awarded 50% in the form of stock options to purchase shares of the Company's common stock and 50% in the form of restricted shares of the Company's common stock. Vesting of the stock option awards and vesting of the restricted stock awards shall require satisfaction of both a service condition and a performance condition. The service condition under each award shall be satisfied on December 31, 2016, subject to Employee's continued employment through such date, and the performance condition shall be satisfied subject to the attainment of a $23.06 closing share price of the Company's common stock for a period of at least 20 out of 30 continuous days on which the shares are quoted or traded at any time during the ten-year term of each award. These awards shall be governed by the terms and conditions of the Long Term Incentive Plan and the terms and conditions set forth in the applicable award agreement. Employee agrees that Employee is not otherwise entitled to these awards, and that these awards provide Employee an interest in the Company that Employee would not otherwise have. Employee also agrees that these awards are good and valuable consideration, which are intended to, and do, protect the Company's interests, including, but not limited to, non-public, confidential, and proprietary information, trade secrets, the Company's Business, and goodwill. Employee also agrees that such consideration is reasonably related to the interests described above, which are worthy of protection. The Company agrees that these awards shall have no effect on the compensation and benefits set forth in Article 6.

Section 4.04. *Partial Forfeiture in the Event of Employee's Breach of Article 11 or Article 12*. In the event of a material breach by Employee of the covenants and promises regarding Noncompetition or Nonsolicitation contained in Article 11 or the covenants and promises regarding Nondisclosure of Confidential and Proprietary Information contained in Article 12, Employee shall forfeit to the Company all but 1,000 restricted shares of the Company's common stock and all outstanding stock options granted on January 15, 2015 and on January 15, 2016 in accordance with the terms of 4.03. In the event the Employee has already sold the restricted shares or stock at the time of said breach, Employee shall tender to the Company an amount equivalent to the sales price of all but 1,000 restricted shares of the Company's common stock granted in Section 4.03. Employee also agrees that the shares that are not subject to forfeiture, as set forth herein, are sufficient consideration that is reasonably related to protect the Company's interests described in Articles 11 and 12, and that those interests, including but not limited to the confidential information and goodwill, are worthy of protection. Nothing in this Section is intended to, nor does it, in any way limit any and all other remedies available to the Company at law or in equity.

ARTICLE 5
CONFIDENTIAL INFORMATION, INVENTIONS,
BUSINESS OPPORTUNITIES AND GOODWILL

Section 5.01. *Confidential Information, Inventions, Business Opportunities and Goodwill*. The Company has and shall continue to: (a) disclose to Employee, and place Employee in a position to have access to or develop, non-public, confidential, or proprietary information and Inventions of the Company (or those of the Company's Affiliates); (b) entrust Employee with business opportunities of the Company (or those of the Company's Affiliates; and (c) place Employee in a position to develop business goodwill on behalf of the Company (or of the Company's Affiliates). The Parties acknowledge and agree that the confidential or proprietary information that has been or will be received by Employee is essential to the performance of Employee's duties. The Parties further acknowledge and agree that the Company has expended many resources, including time and money, in developing its confidential and proprietary information, and that the consideration and promises made herein, including those in Article 11, 12, and 13 are reasonably related to the protection of the Company's confidential and proprietary information and other interests, including goodwill.

ARTICLE 6
COMPENSATION AND BENEFITS

Section 6.01. *Base Salary*. During the term of this Agreement, Employee shall receive a minimum, annualized base salary of an amount not less than the

amount Employee was receiving as of the Agreement's Effective Date (the "**Base Salary**"). Employee's Base Salary shall be reviewed periodically by the Board (or a committee thereof) and, in the sole discretion of the Board (or a committee thereof), the Base Salary may be increased (but not decreased) effective as of any date determined by the Board (or a committee thereof). Employee's Base Salary shall be paid in equal installments in accordance with the Company's standard policy regarding payment of compensation to employees, but no less frequently than monthly.

Section 6.02. *Bonuses.* Employee shall be eligible to receive an annual, calendar-year bonus (payable in a single lump sum) based on criteria determined at the discretion of the Board (or a committee thereof) (the "**Annual Bonus**"), it being understood that (a) the target bonus at planned or targeted levels of performance shall equal to a percentage of Employee's Base Salary that is not less than the target percentage Employee was receiving as of the Agreement's Effective Date and (b) the actual amount of each Annual Bonus shall be determined at the discretion of the Board (or a committee thereof). The Company shall use commercially reasonable efforts to pay each Annual Bonus with respect to a calendar year on or before March 15 of the following calendar year (and in no event shall an Annual Bonus be paid after December 31 of the following calendar year).

Section 6.03. *Long-Term Equity Incentive Compensation.* On an annual basis, Employee shall be eligible to receive long term equity incentive awards under the Long Term Incentive Plan or any successor plan thereto.

Section 6.04. *Other Benefits.* During Employee's employment hereunder, Employee shall be permitted to participate in all benefit plans and programs of the Company, including improvements or modifications of the same, which are now, or may hereafter be, available to other senior Employees of the Company. The Company shall not, however, by reason of this Section 6.04, be obligated to institute, maintain, or refrain from changing, amending, or discontinuing, any such benefit plan or program, so long as such changes are similarly applicable to other senior employees generally.

Section 6.05. *Expenses.* The Company shall reimburse Employee for all reasonable business expenses incurred by Employee in performing services hereunder, including all expenses of travel and living expenses while away from home on business or at the request of and in the service of the Company; provided, in each case, that such expenses are incurred and accounted for in accordance with the policies and procedures established by the Company. Any such reimbursement of expenses shall be made by the Company upon or as soon as practicable following receipt of supporting documentation reasonably satisfactory to the Company (but in any event not later than the close of Employee's taxable year following the taxable year in which the expense is incurred by Employee); provided, however, that, upon Employee's termination of employment with the

Company, in no event shall any additional reimbursement be made prior to the date that is six months after Employee's termination of employment with the Company to the extent such payment delay is required under Section 409A(a)(2)(B)(i) of the Code.

Section 6.06. *Vacation and Sick Leave.* During Employee's employment hereunder, Employee shall be entitled to vacation and other paid time off in accordance with the Company's standard vacation and paid time off policy, as in effect from time to time.

Section 6.07. *Offices.* Subject to Articles 3 and 6, Employee agrees to serve without additional compensation, if elected or appointed thereto, as a director of the Company or any Affiliate and as a member of any committees of the board of directors of any such entities, and in one or more Employee positions of any Affiliate.

Section 6.08. *Clawback Provisions.* Notwithstanding any other provisions in this Agreement to the contrary, any incentive-based compensation, or any other compensation, paid to Employee pursuant to this Agreement or any other agreement or arrangement with the Company which is subject to recovery under any law, government regulation or stock exchange listing requirement, will be subject to such deductions and clawback as may be required to be made pursuant to such law, government regulation or stock exchange listing requirement (or any policy adopted by the Company pursuant to any such law, government regulation or stock exchange listing requirement). To the extent the clawback results in a deduction from wages or a final paycheck, Employee expressly authorizes the Company to make such deductions (pursuant to the Texas Payday Act).

ARTICLE 7
TERMINATION OF EMPLOYMENT; NOTICE
OF TERMINATION OF EMPLOYMENT; NOTICE OF NON-RENEWAL

Section 7.01. *Termination of Employment.* Employee's employment with the Company may be terminated by the Company or Employee under the following circumstances: (a) Employee's death; (b) Employee's Disability; (c) termination by the Company for Cause; (d) termination by the Company without Cause; (e) resignation by Employee for Good Reason; or (f) resignation by Employee without Good Reason. For all purposes of this Agreement, Employee shall be considered to have terminated employment with the Company when Employee incurs a Separation from Service.

Section 7.02. *Notice of Termination of Employment.* Any termination of Employee's employment by the Company or by Employee (other than termination by reason of Employee's death) shall be communicated in writing to the other party indicating the specific termination provision in the first sentence of Section

7.021 relied upon, setting forth in reasonable detail the facts and circumstances claimed to provide a basis for the termination of Employee's employment under the provision so indicated, and specifying a Date of Termination of Employment which, if submitted by Employee, shall be at least 30 days following the date of such notice (a "**Notice of Termination of Employment**"); *provided*, *however*, that in the case of any Notice of Termination of Employment submitted by Employee, the Company may, in its sole discretion, advance the Date of Termination of Employment to any date following the Company's receipt of the Notice of Termination of Employment (and, if the Date of Termination of Employment is so advanced, it shall not change the basis for Employee's termination nor be construed or interpreted as a termination of Employee's employment by the Company for any reason whatsoever). A Notice of Termination of Employment submitted by the Company may provide for a Date of Termination of Employment on the date Employee receives the Notice of Termination of Employment, or any date thereafter elected by the Company in its sole discretion. If the Company is terminating Employee's employment for Cause, the Company shall provide employee with a Notice of Termination of Employment and allow Employee 30 days following the date of such Notice of Termination to fully remedy, cure, or rectify, if possible, the situation giving rise to the Company's allegations of Cause. The cessation of employment of Employee shall not be deemed to be for Cause unless and until there shall have been delivered to Employee a copy of a resolution duly adopted by the affirmative vote of a majority of the entire membership of the Board (excluding Employee, if Employee is a member of the Board) at a meeting of the Board at which at least a quorum is present (after reasonable notice is provided to Employee and Employee is given an opportunity, together with counsel for Employee, to be heard before the Board) finding that, in the good faith opinion of the Board, Employee is guilty of the conduct described in this definition, and specifying the particulars thereof in detail. The failure by Employee or the Company to set forth in the Notice of Termination of Employment any fact or circumstance which contributes to a showing of Cause or Good Reason shall not waive any right of Employee or the Company hereunder or preclude Employee or the Company from asserting such fact or circumstance in enforcing Employee's or the Company's rights hereunder.

Section 7.03. *Deemed Resignations.* Unless otherwise agreed to in writing by the Company and Employee prior to the termination of Employee's employment, any termination of Employee's employment shall constitute an automatic resignation of Employee: (i) as an officer of the Company and each Affiliate; (ii) as a member of the Board (if applicable); (iii) from the board of directors or similar governing body of any Affiliate; and (iv) from the board of directors or similar governing body of any corporation, limited liability entity or other entity in which the Company or any Affiliate holds an equity interest and with respect to which board or similar governing body Employee serves as the Company's or such Affiliate's designee or other representative.

Section 7.04. *Notice of Non-Renewal of This Agreement.* In accordance with Section 2.01 of this Agreement, an election by the Company or by Employee not to extend the Employment Term under this Agreement shall be communicated in writing to the other party hereto (a "**Notice of Non-Renewal**"). A Notice of Non-Renewal communicated by the Company or by Employee shall not constitute a Notice of Termination of Employment.

ARTICLE 8
SEVERANCE BENEFITS

Section 8.01. *Death, Disability, Termination for Cause or Resignation Without Good Reason.* If Employee's employment with the Company is terminated by the Company for Cause or by Employee without Good Reason, or if such employment terminates by reason of Employee's death or Disability, then, upon such termination, Employee (or Employee's estate) shall be entitled to receive the Accrued Obligations (other than in the case of a termination by the Company for Cause, any bonus or incentive compensation that under the applicable plan requires Employee to be employed on the date of payment). If Employee's employment with the Company terminates by reason of death or Disability, then the Company shall also pay to Employee (or Employee's estate or legal representatives, as applicable) on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus.

Section 8.02. *Involuntary Termination.* If Employee's employment with the Company is subject to an Involuntary Termination, Employee shall be entitled to receive the Accrued Obligations and, subject to the provisions of Section 16.09, the Company will, as additional compensation for services rendered to the Company (including its Affiliates), pay to Employee the following amounts and take the following actions after the last day of Employee's employment with the Company:

(a) if the Involuntary Termination occurs prior to a Change in Control or on or after the second anniversary of the Change in Control, pay to Employee in equal monthly installments an amount in cash equal to the Severance Amount, the first installment to be paid on the date that is 60 days after the date of Employee's termination of employment with the Company and subsequent installments to be paid on the first day of each of the next 11 calendar months thereafter or such lesser number of installments such that no installment is paid after March 1st of the year following the year in which Employee's employment was terminated, with each installment equal to the Severance Amount divided by the total number of such installments to be paid;

(b) if the Involuntary Termination occurs on the date of a Change in Control or before the second anniversary of the Change in Control, pay to Employee on the date that is 60 days after the date of Employee's termination of

employment with the Company a lump sum cash payment in an amount equal to the Severance Amount;

(c) pay to Employee on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus; provided, however, that this paragraph shall apply with respect to such Pro Rata Bonus only to the extent the applicable performance criteria have been satisfied as certified by a committee of the Board as required under Section 162(m) of the Code; and

(d) an additional lump sum cash payment in the amount of $25,000 to be paid on the same day as the first installment is paid pursuant to Section 8.02(a) (or, if applicable, on the same day as the lump sum cash payment is paid pursuant to Section 8.02(b)).

Section 8.03. *Death, Disability or Involuntary Termination After Agreement Termination Date.* If, after the Agreement Termination Date but prior to the payment date of the Annual Bonus for the calendar year in which the Agreement Termination Date occurs, Employee's employment with the Company terminates by reason of the Employee's death or by reason of what would have otherwise qualified as Disability or an Involuntary Termination under this Agreement if this Agreement was still in effect at the time of such termination of employment, the Company shall pay to Employee (or Employee's estate or legal representatives, as applicable), subject to the provisions of Section 16.09, on the Pro Rata Bonus Payment Date an amount in cash equal to the Pro Rata Bonus.

ARTICLE 9
VESTING OF CERTAIN EQUITY-BASED AWARDS UPON EXPIRATION OF INITIAL TERM OF THIS AGREEMENT

Section 9.01. *Vesting of Certain Equity-Based Awards.* Notwithstanding the terms of the Company's Long Term Incentive Plan or any applicable award agreement thereunder, subject to Employee's continuing employment hereunder until December 31, 2016, on such date, all of Employee's time-vesting awards of restricted stock, restricted stock units, if applicable, and stock options under the Company's Long Term Incentive Plan that remain outstanding as of December 31, 2016 shall fully vest; *provided* that the vested shares underlying such awards may not be Transferred (as defined below) until the regular scheduled vesting date(s) set forth in the award agreement(s) applicable to such award(s) and further, such vested shares shall be subject to the forfeiture provision contain in Section 4.04 if Employee materially breaches the covenants set forth in Article 11 or Article 12. "**Transfer**" means (a) offer, sell, pledge or hypothecate any legal or beneficial interest, including the grant of an option or other right, or otherwise transfer or enter into an agreement to do so or (b) enter into any hedge, swap or any other agreement that transfers, in whole or in part, any of the economic consequences of ownership (whether such

transaction is settled by delivery of cash, shares or otherwise); *provided* that Employee may sell a sufficient number of vested shares in order to satisfy the income tax obligations that Employee will incur in connection with the vesting of such awards on December 31, 2016.

ARTICLE 10
INTEREST ON LATE PAYMENTS

Section 10.01. *Interest on Late Payments.* If any payment provided for in Section 8.02(a), (b) or (c) or Section 8.03 is not made when due, then the Company shall pay to Employee interest on the amount payable from the date that such payment should have been made under such section until such payment is made, which interest shall be calculated at 5% plus the prime rate of interest announced by JPMorgan Chase Bank, or any successor thereto, at its principal office in New York, and shall change when and as any such change in such prime rate shall be announced by such bank, or any successor thereto.

ARTICLE 11
COMPETITION

Section 11.01. *Competition.* Employee and the Company agree to the restrictive covenants of this Article 11: (i) in consideration for the confidential information provided by the Company to Employee pursuant to Article 5 or otherwise during the course of his employment; (ii) as part of the consideration for the compensation and benefits to be paid to Employee by the Company; (iii) in consideration for the vesting of equity-based awards provided pursuant to Section 9.01; (iv) to reasonably protect the trade secrets and confidential and proprietary information of the Company disclosed or entrusted to Employee by the Company and the goodwill of the Company, or its Affiliates and subsidiaries, developed through the efforts of Employee and/or the business opportunities disclosed or entrusted to Employee by the Company; and (v) as an additional incentive for the Company to enter into this Agreement.

(a) As used in this Article 11, (i) the term "**Company**" shall include the Company and its Affiliates and subsidiaries, and (ii) the term "**Business**" shall mean the exploration for, and the development and production of, oil and natural gas and the acquisition of leases and other real property in connection therewith, as such business may be expanded or altered by the Company during the period of Employee's employment by the Company; *provided*, that any business or endeavor shall cease to be the "Business" if the Company is not or ceases to be engaged in such business or endeavor.

(b) Employee shall not at any time while employed by the Company and for a 1-year period following the Date of Termination of Employment (the

"**Non-Compete Period**") directly or indirectly provide any service (whether as director, officer, employee, agent, representative, consultant or otherwise) in any geologic basin in which the Company has material Business interests that involve the use of similar geologic concepts employed by the Company in such geologic basin at the time in question.

(c)During the Non-Compete Period, Employee shall not, directly or indirectly, recruit or otherwise solicit or induce any employee of the Company, (i) to terminate or forego his or her actual or prospective employment with the Company, or (ii) to establish any relationship with Employee or any of Employee's affiliates, employers, or prospective employers, for any business purpose competitive with the Business of the Company; or (iii) provide the name(s) and/or contact information of any current employee of the Company to Employee's potential or subsequent employer(s), *provided*, *however*, that a general solicitation of the public for employment shall not constitute a solicitation hereunder so long as such general solicitation is not designed to target any employee of the Company.

(d)During the Non-Compete Period, Employee shall not directly or indirectly: (i) interfere with, disrupt, or attempt to disrupt the relationship, contractual or otherwise, between the Company and any current, potential, or prospective customer, vendor, supplier, subcontractor, lessor, lessee, employee, independent contractor, consultant, joint venturer, banker, financier, or investor of the Company, or in any way encourage them to terminate, resign, or otherwise alter their relationship with the Company; or (ii) solicit, call on, suggest, induce, entice away, interfere with, attempt to divert, accept business from or market services or products to, encourage, facilitate, or otherwise benefit from any person, current, potential, or prospective customer, vendor, supplier, subcontractor, lessor, lessee, employee, independent contractor, consultant, joint venturer, banker, financier, or investor of the Company.

(e)Employee and the Company agree that the foregoing covenants are reasonable under the circumstances, necessary to protect the Company's Business and interests, goodwill, confidential information, and other business assets the covenants are intended to protect, and that any breach of such restrictions would cause irreparable injury to the Company. Employee understands that the foregoing restrictions may limit Employee's ability to engage in certain businesses anywhere in the United States and outside the United States during the Non-Compete Period but acknowledges that Employee will receive sufficiently high remuneration and other benefits from the Company to justify such restrictions. Further, Employee acknowledges that Employee's skills are such that he can be gainfully employed in non-competitive employment, and that the agreement not to compete will not prevent Employee from earning a living. Nevertheless, in the event the terms of this Article 11 shall be determined by any court of competent jurisdiction to be unenforceable by reason of its extending for too great a period of time or over too great a geographical area or by reason of its

being too extensive in any other respect, it will be interpreted to extend only over the maximum period of time for which it may be enforceable, over the maximum geographical area as to which it may be enforceable, or to the maximum extent in all other respects as to which it may be enforceable, all as determined by such court in such action.

(f) Employee hereby represents to the Company that he has read and understands, and agrees to be bound by, the terms of this Article 11. Employee acknowledges that the geographic scope and duration of the covenants contained in this Article 11 are the result of arm's-length bargaining and are fair and reasonable in light of (i) the nature and wide geographic scope of the Company's operations of, and in, the Business, (ii) Employee's level of control over and contact with the Company's operations of, and in, the Business in all locales in which it is conducted, (iii) the geographic breadth in which the Company conducts the Business and (iv) the amount of consideration (including confidential information and trade secrets) that Employee is receiving from the Company.

(g) In consideration of the Company's promises herein, during the Non-Compete Period, Employee promises to disclose to the Company any employment, consulting, or other service relationship that Employee enters into after the termination of Employee's employment with the Company for any reason. Such disclosure shall be made within seven business days after Employee enters into such employment, consulting or other service relationship. Employee expressly consents to and authorizes the Company to disclose both the existence and terms of this Agreement to any future employer or recipient of Employee's services and to take any steps the Company deems necessary to enforce this Agreement.

ARTICLE 12
NONDISCLOSURE OF CONFIDENTIAL AND PROPRIETARY INFORMATION

Section 12.01. *Nondisclosure of Confidential and Proprietary Information.* (a) Except in connection with the faithful performance of Employee's duties for the Company or pursuant to Section 12.01(c) or (e), Employee shall, in perpetuity, maintain in confidence and shall not directly, indirectly or otherwise, (i) use, disseminate, disclose or publish, or use for his benefit or the benefit of any person, firm, corporation or other entity, any (A) confidential or proprietary information or trade secrets of or relating to the Company (including, without limitation, intellectual property in the form of patents, trademarks and copyrights and applications therefor, ideas, inventions, works, discoveries, improvements, information, documents, formulae, practices, processes, methods, developments, source code, modifications, technology, techniques, data, programs, other know-how or materials, in each case, that are confidential and/or proprietary and owned, developed or possessed by the Company, whether in tangible or intangible form) or (B) confidential or proprietary information with respect to the Company's

operations, processes, products, inventions, business practices, strategies, business plans, finances, principals, vendors, suppliers, customers, bankers, financiers, investors, potential customers, marketing methods, costs, prices, contractual relationships, regulatory status, prospects and compensation paid to employees or other terms of employment or (ii) deliver to any person, firm, corporation or other entity any document, record, notebook, computer program or similar repository of or containing any such confidential or proprietary information or trade secrets. The parties hereby stipulate and agree that as between them the foregoing matters are important, material and confidential proprietary information and trade secrets and materially affect the successful conduct of the businesses of the Company (and any successor or assignee of the Company).

(b) Upon the termination of Employee's employment with the Company for any reason, Employee will promptly deliver to the Company all correspondence, drawings, manuals, letters, notes, notebooks, reports, programs, plans, proposals, financial documents and electronically stored information, in each case, that are confidential or proprietary to the Company, or any other confidential or proprietary documents (including electronically stored information) concerning the Company's customers, business plans, strategies, products or processes.

(c) Employee may respond to a lawful and valid subpoena or other legal process relating to the Business of the Company or the performance of his duties on behalf of the Company but shall (i) give the Company prompt notice thereof, (ii) make available to the Company and its counsel the documents and other information sought that are not subject to a binding confidentiality agreement and (iii) assist such counsel at Company's expense in resisting or otherwise responding to such process.

(d) As used in this Article 12 and Article 13, the term "**Company**" shall include the Company and its Affiliates and subsidiaries.

(e) Nothing in this Agreement shall prohibit Employee from (i) disclosing information and documents when required by law, subpoena, court order or legal process, (ii) disclosing information and documents to his immediate family members or, for the purpose of securing legal or tax advice, attorney or tax adviser (provided that the persons to whom such disclosures are made shall be informed of their obligation to maintain the strict confidentiality of any information provided to them), (iii) disclosing the post-employment restrictions in this Agreement in confidence to any potential new employer or person or entity to whom he may provide consulting services, or (iv) retaining, at any time, his personal correspondence and rolodex or address book and documents related to his own personal benefits, entitlements and obligations.

ARTICLE 13
INVENTIONS

Section 13.01. *Inventions*. All rights to discoveries, inventions, improvements and innovations (including all data and records pertaining thereto) related to the Business of the Company, whether or not patentable, copyrightable, registrable as a trademark, or reduced to writing, that Employee may discover, invent or originate during the period of his employment with the Company, either alone or with others and whether or not during working hours or by the use of the facilities of the Company ("**Inventions**"), shall be the exclusive property of the Company. Employee shall promptly disclose all Inventions to the Company, shall execute at the request of the Company any assignments or other documents the Company may deem reasonably necessary to protect or perfect its rights therein, and shall assist the Company, upon reasonable request and at the Company's expense, in obtaining, defending and enforcing the Company's rights therein. Employee hereby appoints the Company as his attorney-in-fact to execute on his behalf any assignments or other documents reasonably deemed necessary by the Company to protect or perfect its rights to any Inventions.

ARTICLE 14
INJUNCTIVE RELIEF

Section 14.01. *Injunctive Relief.* It is recognized and acknowledged by Employee that a breach of the covenants contained in Articles 11, 12, 13 and 15 will cause irreparable damage to Company and its Affiliates and their goodwill, the exact amount of which will be difficult or impossible to ascertain, and that the remedies at law for any such breach will be inadequate. Accordingly, Employee agrees that in the event of a breach of any of the covenants contained in Articles 11, 12, 13 and 15, in addition to any other remedy which may be available at law or in equity, the Company will be entitled to specific performance and injunctive relief. It is also agreed that seeking or obtaining such equitable or injunctive relief shall not waive a Party's ability to compel or seek arbitration under the terms of this Agreement.

ARTICLE 15
NON-DISPARAGEMENT

Section 15.01. *Non-Disparagement.* During Employee's employment with the Company and following termination of his employment with the Company for any reason, (a) Employee agrees not to disparage in any material respect the Company, its Affiliates or subsidiaries, any of their products or practices, or any of their directors, officers, agents, representatives, members, partners or stockholders, either orally or in writing, and (b) the Company agrees that it and its Affiliates and subsidiaries will (i) not make any formal statements that disparage in

any material respect Employee and (ii) use commercially reasonable efforts to advise its directors and officers not to disparage in any material respect Employee.

ARTICLE 16
GENERAL

Section 16.01. *Survivorship.* The respective rights and obligations of the parties hereunder shall survive any termination of this Agreement to the extent necessary for the intended preservation of such rights and obligations.

Section 16.02. *Arbitration.* Any dispute or controversy arising under or in connection with this Agreement shall be settled exclusively by arbitration, conducted before an arbitrator in Houston, Texas in accordance with the National Rules for the Resolution of Employment Disputes of the American Arbitration Association then in effect, except that the Company shall be entitled to seek a restraining order, injunction, or other equitable relief, and expedited discovery necessary for the proceedings to obtain said equitable or injunctive relief, in order to prevent or cease any violation or continuation of any violation of the provisions of Articles 11, 12, 13 or 15 of this Agreement, and to obtain specific performance of said Articles. Employee hereby consents that such restraining order or injunction may be granted without requiring the Company to post a bond larger than $500. Employee also agrees that waiver shall not be a defense to Company's invocation of the Agreement's arbitration clause subsequent to any proceeding to obtain the equitable or injunctive relief described herein. Further, for purposes of obtaining said equitable and injunctive relief, Employee consents to the personal jurisdiction and venue of any Texas State court or United States court located in Harris County, Texas. Judgment may be entered on the arbitration award in any court having jurisdiction. Only individuals who are on the AAA register of arbitrators shall be selected as an arbitrator. Within 20 days of the conclusion of the arbitration hearing, the arbitrator(s) shall prepare written findings of fact and conclusions of law. It is mutually agreed that the written decision of the arbitrator(s) shall be valid, binding, final and non-appealable; provided however, that the parties hereto agree that the arbitrator shall not be empowered to award punitive damages against any party to such arbitration. The Company shall bear all administrative fees and expenses of the arbitration and each party shall bear its own counsel fees and expenses except as otherwise provided in this paragraph. If Employee makes a claim against the Company relating to the performance of, or the rights and obligations of, the Company arising under, relating to or in connection with this Agreement (a "**Covered Claim by the Employee**"), the arbitrators shall award Employee his reasonable legal fees and expenses if Employee prevails on one material Covered Claim by the Employee (as determined by the arbitrator). If a claim is made by the Company against Employee relating to the performance of, or the rights and obligations of, Employee arising under, relating to or in connection with this Agreement (a "**Covered Claim by the Company**"), the arbitrators shall award Employee his

reasonable legal fees and expenses; *provided* that if such Covered Claim by the Company relates to Employee's performance or obligations under Articles 11, 12, 13 or 15, the arbitrators shall award Employee his legal fees and expenses only if the Company does not prevail on any Covered Claim by the Company relating to any such Section (as determined by the arbitrator). Any reimbursement of reasonable legal fees and expenses required under this Section 16.02 and any reimbursement of expenses included in the Accrued Obligations payable to Employee under Article 6 shall be made not later than the close of Employee's taxable year following the taxable year in which Employee incurs the expense; *provided*, *however*, that, upon Employee's termination of employment with the Company, in no event shall any additional reimbursement be made prior to the date that is six months after the date of Employee's termination of employment to the extent such payment delay is required under Section 409A(a)(2)(B)(i) of the Code. In no event shall any reimbursement be made to Employee for such fees and expenses incurred after the date that is 10 years after the date of Employee's termination of employment with the Company.

Section 16.03. *Payment Obligations Absolute.* The Company's obligation to pay Employee the amounts and to make the arrangements provided herein shall be absolute and unconditional and shall not be affected by any circumstances, including, without limitation, any set-off, counterclaim, recoupment, defense or other right which the Company (including its Affiliates and subsidiaries) may have against him or anyone else. All amounts payable by the Company shall be paid without notice or demand. Employee shall not be obligated to seek other employment in mitigation of the amounts payable or arrangements made under any provision of this Agreement, and the obtaining of any such other employment shall in no event effect any reduction of the Company's obligations to make (or cause to be made) the payments and arrangements required to be made under this Agreement.

Section 16.04. *Successors.* This Agreement shall be binding upon and inure to the benefit of the Company and any successor of the Company, by merger or otherwise. This Agreement shall also be binding upon and inure to the benefit of Employee and his estate. If Employee shall die prior to full payment of amounts due pursuant to this Agreement, such amounts shall be payable pursuant to the terms of this Agreement to his estate.

Section 16.05. *Severability.* Any provision in this Agreement which is prohibited or unenforceable in any jurisdiction by reason of applicable law shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating or affecting the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 16.06. *Non-alienation.* Employee shall not have any right to pledge, hypothecate, anticipate or assign this Agreement or the rights hereunder, except by will or the laws of descent and distribution.

Section 16.07. *Notices.* Any notices or other communications provided for in this Agreement shall be sufficient if in writing. In the case of Employee, such notices or communications shall be effectively delivered if hand-delivered to Employee at his principal place of employment or if sent by registered or certified mail to Employee at the last address he has filed with the Company. In the case of the Company, such notices or communications shall be effectively delivered if sent by registered or certified mail to the Company at its principal Employee offices.

Section 16.08. *Controlling Law and Waiver of Jury Trial.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Texas. With respect to any claim or dispute related to or arising under this Agreement, Employee and the Company hereby consent to the exclusive jurisdiction, forum and venue of the state and federal courts located in Harris County, Texas. Notwithstanding the foregoing, Section 4.01 and the transfer restrictions set forth in Annex II of the Prior Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware. Furthermore, with respect to any claim or dispute related to or arising under Section 4.01 and the transfer restrictions set forth in Annex II of the Prior Agreement, Employee and the Company hereby consent to the exclusive jurisdiction, forum and venue of the Court of Chancery of the State of Delaware. Each of the parties hereto hereby irrevocably waives any and all right to trial by jury in any legal proceeding arising out of or related to this Agreement or the transactions contemplated hereby.

Section 16.09. *Release and Delayed Payment Restriction.* (a) As a condition to the receipt of any benefit under Article 5 hereof (except in the case of the termination of Employee's employment with the Company by reason of Employee's death or Disability and except for the Accrued Obligations), Employee shall first execute a release in the form attached hereto as Exhibit A (with such changes therein as the Company may reasonably require to reflect changes in applicable law and the circumstances relating to the termination of Employee's employment), releasing the Company and certain other persons and entities from certain claims and other liabilities.

(b)The release described in Section 16.09(a) hereof must be effective and irrevocable within 55 days after the date of the termination of Employee's employment with the Company. Notwithstanding any provision in this Agreement to the contrary, if the payment of any amount or benefit under this Agreement would be subject to additional taxes and interest under Section 409A of the Code because the timing of such payment is not delayed as provided in Section 409A(a)(2)(B)(i) of the Code and the regulations thereunder, then any such payment or benefit that Employee would otherwise be entitled to during the first six months following the date of Employee's termination of employment

shall be accumulated and paid or provided, as applicable, on the date that is six months after the date of Employee's termination of employment (or if such date does not fall on a business day of the Company, the next following business day of the Company), or such earlier date upon which such amount can be paid or provided under Section 409A of the Code without being subject to such additional taxes and interest. If this Section 16.09(b) becomes applicable such that the payment of any amount is delayed, any payments that are so delayed shall accrue interest on a non-compounded basis, from the date such payment would have been made had this Section 16.09(b) not applied to the actual date of payment, at the prime rate of interest announced by JPMorgan Chase Bank (or any successor thereto) at its principal office in New York on the date of Employee's termination of employment (or the first business day following such date if such termination does not occur on a business day) and shall be paid in a lump sum on the actual date of payment of the delayed payment amount. Employee hereby agrees to be bound by the Company's determination of its "specified employees" (as such term is defined in Section 409A of the Code) in accordance with any of the methods permitted under the regulations issued under Section 409A of the Code.

Section 16.10. *Full Settlement.* If Employee is entitled to and receives the benefits provided hereunder, performance of the obligations of the Company hereunder will constitute full settlement of all claims that Employee might otherwise assert against the Company on account of his termination of employment.

Section 16.11. *Unfunded Obligation.* The obligation to pay amounts under this Agreement is an unfunded obligation of the Company, and no such obligation shall create a trust or be deemed to be secured by any pledge or encumbrance on any property of the Company.

Section 16.12. *No Right to Continued Employment.* Employee and the Company recognize and agree that subject to the terms of this Agreement (including the notice provisions of Section 7.02), (i) the Company may terminate Employee's employment at any time, for any reason or no reason at all and (ii) Employee may terminate his employment at any time, for any reason or no reason at all.

Section 16.13. *Withholding of Taxes and Other Employee Deductions.* The Company may withhold from any benefits and payments made pursuant to this Agreement (whether actually or constructively made to Employee or treated as included in Employee's income under Section 409A of the Code) all federal, state, city, foreign and other applicable taxes and withholdings as may be required pursuant to any law or governmental regulation or ruling and all other customary deductions made with respect to the Company's employees generally.

Section 16.14. *Number and Gender.* Wherever appropriate herein, words used in the singular shall include the plural and the plural shall include the singular.

The masculine gender where appearing herein shall be deemed to include the feminine gender.

Section 16.15. *Entire Agreement.* Except as provided in Section 2.02, this Agreement, including the Exhibit attached hereto, constitutes the entire agreement of the parties with regard to the subject matter hereof and supersedes any and all prior understandings, agreements or correspondence between the parties. Any modification of this Agreement will be effective only if it is in writing and signed by the party to be charged.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the date and year first written above.

EMPLOYEE

By: /s/ James H. Painter

Name: James H. Painter

Title: Executive Vice President, Execution and Appraisal

COBALT INTERNATIONAL ENERGY, INC.

By: /s/ Joseph H. Bryant

Name: Joseph H. Bryant

Title: Chairman and Chief Executive Officer

EXHIBIT A

FORM OF RELEASE

For and in consideration of certain payments and other benefits due to [•] ("**Employee**") pursuant to the Employment Agreement (the "**Employment Agreement**") dated as of [•], 20 , between Cobalt International Energy, Inc., (the "**Company**") and Employee, and for other good and valuable consideration, Employee hereby agrees, for Employee, Employee's spouse and child or children (if any), Employee's heirs, beneficiaries, devisees, executors, administrators, attorneys, personal representatives, successors and assigns, to forever release, discharge and covenant not to sue the Company and its divisions, Affiliates, subsidiaries, parents, branches, predecessors, successors, assigns, and, with respect to such entities, their officers, directors, trustees, employees, agents, shareholders, administrators, general or limited partners, members, representatives, attorneys, insurers and fiduciaries, past, present and future (the "**Released Parties**") from any and all claims of any kind arising out of, or related to, his employment with the Company, its Affiliates or subsidiaries (collectively, with the Company, the "**Affiliated Entities**") or Employee's separation from employment with the Affiliated Entities, which Employee now has or may have against the Released Parties, whether known or unknown to Employee, by reason of facts which have occurred on or prior to the date that Employee has signed this Release. Such released claims include, without limitation, any and all claims relating to the foregoing under federal, state or local laws pertaining to employment, including, without limitation, the Age Discrimination in Employment Act, Title VII of the Civil Rights Act of 1964, as amended, 42 U.S.C. Section 2000e *et seq*., the Fair Labor Standards Act, as amended, 29 U.S.C. Section 201 *et seq*., the Americans with Disabilities Act, as amended, 42 U.S.C. Section 12101 *et seq*. the Reconstruction Era Civil Rights Act, as amended, 42 U.S.C. Section 1981 *et seq*., the Rehabilitation Act of 1973, as amended, 29 U.S.C. Section 701 *et seq*., the Family and Medical Leave Act of 1992, 29 U.S.C. Section 2601 *et seq*., and any and all state or local laws regarding employment discrimination, the payment of wages and/or federal, state or local laws of any type or description regarding employment, including but not limited to any claims arising from or derivative of Employee's employment with the Affiliated Entities, as well as any and all such claims under state contract or tort law. By signing this Release, Employee is bound by it. Anyone who succeeds to Employee's rights and responsibilities, such as heirs or the executor of Employee's estate, is also bound by this Release. This Release also applies to any claims brought by any person or agency or class action under which Employee may have a right or benefit. Notwithstanding this release of liability, nothing in this Release prevents Employee from filing any non-legally waivable claim (including a challenge to the validity of this Release) with the Equal Employment Opportunity Commission (the "**EEOC**") or comparable state or local agency or participating in any investigation or proceeding conducted by the EEOC or comparable state or local agency; however, Employee understands and agrees that Employee is waiving

any and all rights to recover any monetary or personal relief or recovery as a result of such EEOC or comparable state or local agency proceeding or subsequent legal actions.

Protections under Older Workers Benefits Protection Act. Employee has read this Release carefully, and acknowledges that Employee fully understands its terms. Further, Employee acknowledges that Employee has been given at least 21 days to consider all of its terms and has been and is hereby advised to consult with an attorney and any other advisors of Employee's choice prior to executing this Release, and Employee fully understands that by signing below Employee is knowingly and voluntarily giving up any right which Employee may have to sue or bring any other claims against the Released Parties, including any rights and claims under the Age Discrimination in Employment Act. Employee also understands that Employee has a period of seven (7) days after signing this Release within which to revoke his agreement, and that neither the Company nor any other person is obligated to make any payments or provide any other benefits to Employee pursuant to the Agreement until eight days have passed since Employee's signing of this Release without Employee's signature having been revoked other than any accrued obligations or other benefits payable pursuant to the terms of the Company's normal payroll practices or employee benefit plans. Finally, Employee expressly represents that he has not been forced or pressured in any manner whatsoever to sign this Release, and Employee agrees to all of its terms knowingly and voluntarily.

Notwithstanding anything else herein to the contrary, this Release shall not affect: (i) the Company's obligations under any compensation or employee benefit plan, program or arrangement (including, without limitation, obligations to Employee under the Employment Agreement or any stock option, stock award or agreements or obligations under any pension, deferred compensation or retention plan) provided by the Affiliated Entities where Employee's compensation or benefits are intended to continue or Employee is to be provided with compensation or benefits, in accordance with the express written terms of such plan, program or arrangement, beyond the date of Employee's termination and (ii) rights to indemnification Employee may have under (A) applicable law, (B) any other agreement between Employee and a Released Party and (C) as an insured under any director's and officer's liability insurance policy now or previously in force. This Release also shall not affect any prospective claims arising after the date of its execution.

This Release is final and binding and may not be changed or modified except in a writing signed by both parties.

Date	**James H. Painter**
	Executive Vice President, Execution and Appraisal
	Cobalt International Energy, Inc.
Date:	By:
	Name:
	Title:

Exhibit 10.36

COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN

Special Restricted Stock Award Agreement
2015 Grant

You have been granted restricted stock (this "**Award**") on the following terms and subject to the provisions of Attachment A and the Cobalt International Energy, Inc. Long Term Incentive Plan (the "**Plan**"). Unless defined in this Award Agreement (including Attachment A, this "**Agreement**"), capitalized terms will have the meanings assigned to them in the Plan. In the event of a conflict among the provisions of the Plan, this Agreement and any descriptive materials provided to you, the provisions of the Plan will prevail.

Participant	[Full Name]
Number of Shares Underlying Award	126,582 (to the extent not vested as of any applicable date, the "**Restricted Shares**")
Grant Date	January 15, 2015
Vesting	Subject to Section 3 of Attachment A, the Award shall fully vest on [Date] (the "**Service Vesting Date**") or such later date on or before [Date] when and only if each of the following conditions is satisfied: • the Participant does not experience a Termination of Service at any time prior to the Service Vesting Date (the "**Service Condition**"); and • at any time during the period that begins on the Grant Date and ends on [Date] (inclusive), the closing price of a Share on the principal stock market or exchange on which the Shares are quoted or traded equals or exceeds $23.06 for a period of at least 20 out of 30 continuous days on which Shares are quoted or traded (the "**Value Condition**").

Attachment A

Restricted Stock Award Agreement
Terms and Conditions

Grant to: [Full Name]

COBALT INTERNATIONAL ENERGY (the "Company") hereby grants [Full Name] ("Employee") certain shares, as set forth below, of the Company's stock, which shall be effective in accordance with the terms herein.

RECITALS

WHEREAS, during the course of Employee's employment, Company has provided and will continue to provide Employee with non-public, confidential, and proprietary information developed by the Company and relating to the Company's business, interests, confidential and proprietary information, methods, products, business plans and strategy, finances, and operations.

WHEREAS, Company invests considerable resources in building partner, vendor, supplier, banking, financier, and investor relationships, and developing strategic plans and goodwill in the energy industry, not only by paying for Employee's services and investing in the development of Employee, but also by investing in research and development, and exploration techniques and technologies which are non-public, confidential, and proprietary;

WHEREAS, Company and Employee acknowledge that the breadth and scope of the Company's operations covers a global territory due to the nature of the oil and natural gas exploration business, the Company's operations and Business (as defined in the Employment Agreement), and the Company's exploration goals and strategy, which Employee has had access to and will continue to have access to in order to perform Employee's duties;

WHEREAS, the Company and Employee agree and understand that this Agreement and the mutual promises and covenants herein are intended to, and do, advance the interests of the Company, including but not limited to the Company's protection of its Confidential Information, goodwill, growth, strategy, and development, and also the interests of Employee, and are also reasonable and necessary to protect Company's Business, confidential and proprietary information, and goodwill;

WHEREAS, the Board of Directors of the Company intends to encourage Employee's continued service to the Company and the development of the Company's short and long-term Business, interests, goals, and goodwill;

WHEREAS, Employee acknowledges and agrees that Employee is not otherwise entitled to the shares granted herein, and that these shares provide Employee an interest in the Company that Employee is not otherwise entitled to;

WHEREAS, Company and Employee agree and acknowledge that the grant of the shares herein are an adequate means to incentivize Employee to contribute to and benefit from the short

and long-term growth and profitability of the Company, and Employee's own growth and development; and

WHEREAS, Employee also acknowledges that the shares granted herein are good and valuable consideration which are intended to, and do, protect the Company's interests, including, but not limited to, the Company's non-public, confidential, and proprietary information, trade secrets, business, and goodwill, and that such consideration is reasonably related to the same, and that such interests are worthy of protection.

GRANT

NOW, THEREFORE, in consideration of the foregoing and in exchange for the promises and covenants herein, the Company grants Employee certain shares of its stock, as follows:

Section 1. *Grant of Restricted Stock Award.*

(a) Subject to the terms and conditions of the Plan and this Agreement and the Employment Agreement, the Company hereby grants Restricted Stock to the Participant on the Grant Date on the terms set forth on the cover page of this Agreement, as more fully described in this Attachment A. This Award is granted under the Plan, which is incorporated herein by this reference and made a part of this Agreement, and your Employment Agreement.

Section 2. *Issuance of Shares.*

(a) The Restricted Shares shall be evidenced by book-entry registration; *provided, however*, that the Company's Compensation Committee of the Board of Directors (hereinafter "Committee") may determine that the Restricted Shares shall be evidenced in such other manner as it deems appropriate, including the issuance of a stock certificate or certificates. In the event that any stock certificate is issued in respect of the Restricted Shares, such certificate shall (i) be registered in the name of the Participant, (ii) bear an appropriate legend referring to the terms, conditions and restrictions applicable to the Restricted Shares and (iii) be held in custody by the Company.

(b) *Voting Rights*. The Participant shall have voting rights with respect to the Restricted Shares.

(c) *Dividends*. All cash and other dividends and distributions, if any, that are paid with respect to any Restricted Shares shall be withheld by the Company and paid to the Participant, without interest, only when, and if, the Restricted Shares become vested in accordance with this Agreement.

(d) *Transferability*. Unless and until the Restricted Shares become vested in accordance with this Agreement, the Restricted Shares shall not be assigned, sold, transferred or otherwise be subject to alienation by the Participant.

(e) *Section 83(b) Election*. If the Participant chooses, the Participant may make an election under Section 83(b) of the Code with respect to the Restricted Shares, which would cause the Participant currently to recognize income for U.S. federal income tax purposes in an amount equal to the excess (if any) of the fair market value of the Restricted Shares (determined as of the Grant Date) over the amount, if any, that the Participant paid for the Restricted Shares, which excess will be subject to U.S. federal income tax. The form for making a Section 83(b) election is attached as Attachment B. **The Participant acknowledges that (i) the Participant is solely responsible for the decision whether or not to make a Section 83(b) election, and the Company is not making any recommendation with respect thereto, (ii) it is his or her sole responsibility to timely file the Section 83(b) election within 30 days after the Grant Date, if the Participant decides to make such election, and (iii) if the Participant does not make a valid and timely Section 83(b) election, the Participant will be required to recognize ordinary income at the time of vesting on any future appreciation on the Restricted Shares.**

(f) *Withholding Requirements*. The Company may withhold any tax (or other governmental obligation) that becomes due with respect to the Restricted Shares (or any dividend or distribution thereon), and the Participant shall make arrangements satisfactory to the Company to enable the Company to satisfy all such withholding requirements. Notwithstanding the foregoing, the Committee may require, in its sole discretion, the Participant to satisfy any such withholding requirement by transferring to the Company pursuant to such procedures as the Committee may require, effective as of the date on which a withholding obligation arises, a number of vested Shares owned and designated by the Participant having an aggregate fair market value as of such date that is equal to the minimum amount required to be withheld. If the Committee permits the Participant to satisfy any such withholding requirement pursuant to the preceding sentence, the Company shall remit to the Internal Revenue Service and appropriate state and local revenue agencies, for the credit of the Participant, an amount of cash withholding equal to the fair market value of the Shares transferred to the Company as provided above. Unless the Participant satisfies his or her obligations to the Company as set forth above in an amount that is sufficient for the Company to satisfy any tax (or other governmental obligation) that becomes due with respect to the Restricted Shares (or any dividend or distribution thereon), the Restricted Shares shall be automatically sold through the Company's stock plan administrator in an amount sufficient to satisfy the Company's withholding obligations; provided, however, that such Restricted Shares shall not be automatically sold if (i) the Participant engaged in a non-exempt opposite-way transaction in the prior six months that could result in profit disgorgement by the Participant to the Company under Section 16(b) of the Exchange Act or (ii) the sale would cause the Participant to violate the Company's insider trading policy.

Section 3. *Vesting of Restricted Shares.*

(a) *Termination of Service*.

(i) *Death or Disability or Termination of Employment by the Company without Cause or by the Participant for Good Reason*. In the event of the Participant's Termination of Service at any time due to the Participant's death or Disability or termination of employment by the Company without Cause or by the Participant for Good Reason, (x) to the extent still applicable, the Service Condition shall be deemed to be satisfied as of the date of such Termination of Service and (y)(1) if the Value Condition is satisfied on or prior to the date of such Termination of Service, the Restricted Shares shall fully vest as of the date of such Termination of Service and (2) if the Value Condition is not satisfied on or prior to the date of such Termination of Service, the Restricted Shares shall vest when and only if the Value Condition is satisfied.

(ii) *Any Other Termination of Service*. In the event of the Participant's Termination of Service at any time prior to the Service Vesting Date for any reason (other than due to the Participant's death or Disability or termination by the Company without Cause or by the Participant for Good Reason), the Restricted Shares shall be forfeited in their entirety as of the date of such termination without any payment to the Participant, except that the Participant shall retain and shall fully vest in one thousand (1,000) Restricted Shares when and only if the Value Condition is satisfied.

Notwithstanding the foregoing, in the event of the Participant's Termination of Service other than by the Company for Cause, the Committee may, in its sole discretion, accelerate the vesting or waive any term or condition of this Agreement, subject to such terms and conditions as the Committee deems appropriate, with respect to all or a portion of the Restricted Shares.

(b) *Change in Control*.

a. If a Change in Control occurs before the Service Vesting Date (regardless of whether the Value Condition has been satisfied), the Restricted Shares shall fully vest as of the date of such Change in Control; *provided* that if prior to the date of such Change in Control, the Company or the acquirer requests in writing that the Participant continue to provide services to the Company (or the successor or surviving entity) for a specified period not to exceed 12 months after such Change in Control, the Restricted Shares shall vest as of the earliest of (x) the last day of such requested period, (y) the Service Vesting Date or (z) the date, if any, of the Participant's Termination of Service by the Company (or the successor or surviving entity) without Cause, by the Participant for Good Reason or due to the Participant's death or Disability (such earliest date, the "Change in Control Vesting Date"). The Restricted Shares shall be forfeited in their entirety, except for those restricted shares not subject to forfeiture pursuant to Section 4.04 of the Employment Agreement, without any payment to the Participant upon his or her Termination of Service by the Company (or the successor or surviving entity) for Cause or by the Participant without Good Reason at any time prior to the Change in Control Vesting Date.

b. If a Change in Control occurs on or after the Service Vesting Date (regardless of whether the Value Condition has been satisfied), the Restricted Shares shall fully vest as of the date of such Change in Control.

(c) *Effect of Vesting*. Subject to the provisions of this Agreement, upon the vesting of Restricted Shares, the restrictions under this Award with respect to such Shares shall lapse, and subject to any applicable Lock Up Agreement or requirement to comply with non-competition covenants, such Shares shall be fully assignable, saleable and transferable by the Participant, and the Company shall deliver such Shares, along with any dividends and other distributions that were paid with respect to such Shares but withheld pending vesting, to the Participant. Subject to any applicable Lock Up Agreement or requirement to comply with non-competition covenants, such Shares shall be delivered by transfer to the Depository Trust Company for the benefit of the Participant or by delivery of a stock certificate registered in the Participant's name.

(d) *Effect of Breaching Restrictive Covenants*. Notwithstanding anything to the contrary in this Agreement, if at any time while the Award remains outstanding, the Participant breaches the Restrictive Covenants (as defined in Section 4(a) of this Agreement), the Restricted Shares shall be forfeited in their entirety, except for those Restricted Shares not subject to forfeiture pursuant to Section 4.04 of the Employment Agreement.

Section 4. *Incorporation of Restrictive Covenants Set Forth in Employment Agreement*

(a) *Incorporation by Reference.* Company and Employee agree that the restrictive covenants set forth in Articles 11, 12, 13, 14, and 15 ("Restrictive Covenants") and Section 4.04 of the Employment Agreement by and between the Company and Employee, dated November 3, 2014, are incorporated by reference herein as if they were part of this Agreement and set forth in it.

(b) *Agreement is Ancillary to the Employment Agreement.* The Parties acknowledge and agree that this Agreement is ancillary to the Employment Agreement, which the Parties are entering into at the same time.

(c) *Covenants are Reasonable and Related to the Company's Business Interests.* The Parties agree that the Restrictive Covenants are reasonable under the circumstances, necessary to protect the Company's business interests, goodwill, confidential information, and other business assets the Restrictive Covenants are intended to protect, and that any breach of such Restrictive Covenants would cause irreparable injury and harm to the Company. Employee understands that the Restrictive Covenants may limit Employee's ability to engage in certain businesses anywhere in the United States and outside of the United States during the Non-Compete Period, as defined in the Employment Agreement and whose definition is incorporated by reference herein, but acknowledges that Employee will receive sufficiently high remuneration and other benefits from the Company to justify such restrictions, and that Employee knowingly

and voluntarily chooses to accept such limitations. Further, Employee acknowledges that his skills are such that he can be gainfully employed in non-competitive employment, and that the Restrictive Covenants will not prevent Employee from earning a living. Nevertheless, in the event the terms of Section 4 or the Restrictive Covenants shall be determined by any court of competent jurisdiction or arbitrator to be unenforceable by reason of their extending for too great a period of time or over too great a geographical area, or by reason of their being too extensive in any other respect, they will be interpreted to extend only over the maximum period of time for which they may be enforceable, over the maximum geographical area as to which they may be enforceable, or to the maximum extent in all other respects as to which they may be enforceable, all as determined by such court or arbitrator in such action.

(d) *Consideration is Reasonably Related to Interests Worthy of Protection*. The Parties acknowledge and agree that Employee has had access to, and shall continue to have access to, the Company's non-public, confidential, and proprietary information, as access to such information is essential to the performance of Employee's duties for the Company. Employee acknowledges and agrees that Employee t is not otherwise entitled to the granting of the shares set forth in this Agreement, and that these shares provide Employee an interest in the Company that Employee would not otherwise have but for his agreement to the Restrictive Covenants. Employee also agrees that the shares are good and valuable consideration, which are intended to, and do, protect the Company's interests, and are reasonably related to the same. The Parties further acknowledge and agree that the Company has expended many resources, including time and money, in developing its confidential and proprietary information and goodwill, and that the consideration and promises made herein, and in the Employment Agreement, are reasonably related to the protection of those interests, and also Employee's and the Company's interest in the short and long-term growth of the Company and in Employee's continued development and growth. Employee and the Company acknowledge and agree that said interests provide the Company a competitive advantage in the market place and that those interests are worthy of protection. Employee acknowledges that but for Employee's agreement to the Restrictive Covenants, Employee would not continue to receive access to the Company's non-public, confidential, and proprietary information, or be granted the shares, as set forth in this Agreement.

(e) *Reasonableness of Time, Scope, and Geography*. Employee hereby represents to the Company that he has read and understands, and agrees to be bound by, the terms of the Restrictive Covenants and Section 4. Employee acknowledges that the geographic scope and duration of the Restrictive Covenants are the result of arm's-length bargaining and are fair and reasonable in light of i) the nature and wide geographic scope of the Company's operations of, and in, the business, as defined in the Employment Agreement and whose definition is incorporated by reference herein, ii) Employee's level of control over and contact with the Company's operations of, and in, the Business in all locales in which it is conducted, iii) the geographic breadth in which the Company conducts the Business, and iv) the amount of consideration (including confidential information and trade secrets) that Employee is receiving from the

Company. In consideration of the Company's promises herein, during the Non-Compete Period, Employee promises to disclose to the Company any employment, consulting, or other service relationship that Employee enters into after the termination of Employee's employment with the Company for any reason. Such disclosure shall be made within seven business days after Employee enters into such employment, consulting or other service relationship. Employee expressly consents to and authorizes the Company to disclose both the existence and terms of this Agreement to any future employer or recipient of Employee's services and to take any steps the Company deems necessary to enforce this Agreement.

(f) *Injunctive Relief*. Employee acknowledges and agrees that a breach of the Restrictive Covenants will cause irreparable damage to the Company and its Affiliates, as defined in the Employment Agreement and whose definition is incorporated by reference herein, and their goodwill, the exact amount of which will be difficult or impossible to ascertain, and that the remedies at law for any such breach will be inadequate. Accordingly, Employee agrees that in the event of a breach of any of the Restrictive Covenants, in addition to any other remedy which may be available at law or in equity, the Company will be entitled to equitable and injunctive relief. Employee and the Company agree that while any dispute or controversy arising under, or in connection with, the Employment Agreement, including a breach of the Restrictive Covenants, shall be settled exclusively by arbitration, conducted before an arbitrator in Houston, Texas in accordance with the National Rules for the Resolution of Employment Disputes of the American Arbitration Association then in effect, the Company shall be entitled to seek a restraining order, injunction, or other equitable relief, and expedited discovery necessary for the proceedings to obtain said equitable or injunctive relief, in order to prevent or cease any violation or continuation of any violation of the provisions of the Restrictive Covenants. Employee consents that such restraining order or injunction may be granted without requiring the Company to post a bond larger than $500. Employee also agrees that waiver shall not be a defense to the Company's invocation of the Employment Agreement's arbitration clause subsequent to any proceeding to obtain the equitable or injunctive relief described under Section 4 and in the Employment Agreement. Further, for purposes of obtaining said equitable or injunctive relief, Employee consents to the personal jurisdiction and venue of any Texas State court or United States Court located in Harris County, Texas.

(g) *Choice of Law, Jurisdiction, Venue for Suits to Enforce Restrictive Covenants*. The Restrictive Covenants and *only* Section 4 of this Agreement shall be governed by, and construed in accordance with the laws of the State of Texas. With respect to any claim or dispute related to or arising under, or in relation to, the Restrictive Covenants and Section 4, including, but not limited to, suits seeking equitable and injunctive relief described in the Employment Agreement, Employee and the Company hereby consent to the exclusive jurisdiction, forum and venue of the state and federal courts located in Harris County, Texas.

Section 5. *Miscellaneous Provisions.*

(a)*Notices*. All notices, requests and other communications under this Agreement shall be in writing and shall be delivered in person (by courier or otherwise), mailed by certified or registered mail, return receipt requested, or sent by facsimile transmission, as follows:

If to the Company, to:

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
Attention: General Counsel
Facsimile: 713-579-9184

If to the Participant, to the address that the Participant most recently provided to the Company, or

To such other address or facsimile number as such party may hereafter specify for the purpose by notice to the other parties hereto. All such notices, requests and other communications shall be deemed received on the date of receipt by the recipient thereof if received prior to 5:00 p.m. on a business day in the place of receipt. Otherwise, any such notice, request or communication shall be deemed received on the next succeeding business day in the place of receipt.

(b)*Entire Agreement*. This Agreement, the Plan, and any other agreements referred to herein and therein and any schedules, exhibits and other documents referred to herein or therein, constitute the entire agreement and understanding between the parties in respect of the subject matter hereof and supersede all prior and contemporaneous arrangements, agreements and understandings, both oral and written, whether in term sheets, presentations or otherwise, between the parties with respect to the subject matter hereof.

(c)*Amendment; Waiver*. No amendment or modification of any provision of this Agreement shall be effective unless signed in writing by or on behalf of the Company and the Participant, except that the Company may amend or modify the Agreement without the Participant's consent in accordance with the provisions of the Plan or as otherwise set forth in this Agreement. No waiver of any breach or condition of this Agreement shall be deemed to be a waiver of any other or subsequent breach or condition whether of like or different nature. Any amendment or modification of or to any provision of this Agreement, or any waiver of any provision of this Agreement, shall be effective only in the specific instance and for the specific purpose for which made or given.

(d)*Assignment*. Neither this Agreement nor any right, remedy, obligation or liability arising hereunder or by reason hereof shall be assignable by the Participant.

(e) *Successors and Assigns; No Third Party Beneficiaries*. This Agreement shall inure to the benefit of and be binding upon the Company and the Participant and their respective heirs, successors, legal representatives and permitted assigns. Nothing in this Agreement, expressed or implied, is intended to confer on any Person other than the Company and the Participant, and their respective heirs, successors, legal representatives and permitted assigns, any rights, remedies, obligations or liabilities under or by reason of this Agreement.

(f) *Counterparts*. This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

(g) *Participant Undertaking*. The Participant agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable to carry out or give effect to any of the obligations or restrictions imposed on either the Participant or the Restricted Shares pursuant to the provisions of this Agreement.

(h) *Plan*. The Participant acknowledges and understands that material definitions and provisions concerning the Restricted Shares and the Participant's rights and obligations with respect thereto are set forth in the Plan. The Participant has read carefully, and understands, the provisions of the Plan.

(i) *Governing Law*. The Agreement, except for Section 4 which shall be governed by the law of the State of Texas, shall be governed by the laws of the State of Delaware, without application of the conflicts of law principles thereof.

(j) *Jurisdiction*. The parties hereto agree that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Agreement or the transactions contemplated hereby (whether brought by any party or any of its affiliates or against any party or any of its affiliates), except any suit, action or proceeding seeking to enforce Section 4 or the Restrictive Covenants, shall be brought in the Delaware Chancery Court or, if such court shall not have jurisdiction, any federal court located in the State of Delaware or other Delaware state court, and each of the parties hereby irrevocably consents to the jurisdiction of such courts (and of the appropriate appellate courts therefrom) in any such suit, action or proceeding and irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such court or that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum, except for suits seeking to enforce Section 4 or the Restrictive Covenants. Process in any such suit, action or proceeding may be served on each party anywhere in the world, whether within or without the jurisdiction of any such court. Without limiting the foregoing, each party agrees that service of process on such party as provided in Section 5(a) shall be deemed effective service of process on such party.

(k) *Severability*. Any provision in this Agreement which is prohibited or unenforceable in any jurisdiction by reason of applicable law shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating or affecting the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

(l) *WAIVER OF JURY TRIAL*. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

COBALT INTERNATIONAL ENERGY, INC.

By: ____________________________________

Name:

Title:

By: ____________________________________

[Full Name]

Attachment B

SECTION 83(b) ELECTION

This statement is being made under Section 83(b) of the Internal Revenue Code, pursuant to Treas. Reg. Section 1.83-2.

(1) The taxpayer performing the services is:

Name:

Address:

Social Security Number:

(2) The property with respect to which the election is being made is shares (the "**Restricted Shares**") of common stock, par value $.01 per share, of Cobalt International Energy, Inc. (the "**Company**")

(3) The Restricted Shares were transferred on .

(4) The taxable year in which the election is being made is the calendar year .

(5) The Restricted Shares are not transferable and are subject to a substantial risk of forfeiture within the meaning of Section 83(c)(1) of the Internal Revenue Code until and unless specified conditions are satisfied or a specified event occurs, in each case as set forth in the Company's Long Term Incentive Plan and the Restricted Stock Award Agreement pursuant to which the Restricted Shares were issued.

(6) The fair market value of the Restricted Shares at the time of transfer (determined without regard to any restriction other than a restriction which by its terms will never lapse) is $ per share.

(7) The amount paid by the taxpayer for the Restricted Shares is $ per share.

(8) A copy of this statement has been furnished to the Company, for whom the taxpayer will be performing services underlying the transfer of the Restricted Shares.

(9) This statement is executed on .

______________________________	______________________________
Spouse (if any)	Taxpayer

This statement must be filed with the Internal Revenue Service Center with which you filed your last U.S. federal income tax return within 30 days after the grant date of the Restricted Stock Award Agreement. This filing should be made by registered or certified mail, return receipt requested. You are also required to (i) deliver a copy of this statement to the Company and (ii) attach a copy of this statement to your federal income tax return for the taxable year that includes the grant date (and may also be required to attach a copy of this statement to your state income tax return for such year). You should also retain a copy of this statement for your records.

Exhibit 10.37

COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN

Special Non-Qualified Stock Option Award Agreement
2015 Grant

You have been granted an option (the "**Option**") to purchase shares of Cobalt International Energy, Inc. (this "**Award**") on the following terms and subject to the provisions of Attachment A and the Cobalt International Energy, Inc. Long Term Incentive Plan (the "**Plan**"). Unless defined in this Award Agreement (including Attachment A, this "**Agreement**"), capitalized terms will have the meanings assigned to them in the Plan. In the event of a conflict among the provisions of the Plan, this Agreement and any descriptive materials provided to you, the provisions of the Plan will prevail.

Participant	[Full Name]
Number of Shares Subject to the Option	248,756 Shares
Option Price per Share	$7.90
Grant Date	January 15, 2015
Expiration Date	January 14, 2025
Vesting	Subject to Section 2 of Attachment A, the Option shall fully vest on [Date] (the "**Service Vesting Date**") or such later date on or before [Date] when and only if each of the following conditions is satisfied: • the Participant does not experience a Termination of Service at any time prior to the Service Vesting Date (the "**Service Condition**"); and • at any time during the period that begins on the Grant Date and ends on [Date] (inclusive), the closing price of a Share on the principal stock market or exchange on which the Shares are quoted or traded equals or exceeds $23.06 for a period of at least 20 out of 30 continuous days on which Shares are quoted or traded (the "**Value Condition**").
Exercise On or	Subject to Section 2 of Attachment A, if the Option vests

Prior to Expiration Date	on or prior to the Expiration Date, the Option shall remain exercisable until the Expiration Date (inclusive).

Attachment A

Non-Qualified Stock Option Award Agreement
Terms and Conditions

Grant to: [Full Name]

Section 1. *Grant of Award.* Subject to the terms and conditions of the Plan and this Agreement, the Company hereby grants an Option to the Participant on the Grant Date on the terms set forth on the cover page of this Agreement, as more fully described in this Attachment A. The Option is intended to be a non-qualified stock option, and is not intended to be treated as an option that complies with Section 422 of the Code. This Award is granted under the Plan, which is incorporated herein by reference and made a part of this Agreement.

Section 2. *Vesting of Award.*

(a)Termination of Service.

(i)*Death or Disability or Termination of Employment by the Company without Cause or by the Participant for Good Reason.* In the event of the Participant's Termination of Service at any time due to the Participant's death or Disability or termination of employment by the Company without Cause or by the Participant for Good Reason, (x) to the extent still applicable, the Service Condition shall be deemed to be satisfied as of the date of such Termination of Service and (y)(1) if the Value Condition is satisfied on or prior to the date of such Termination of Service, the Option shall fully vest as of the date of such Termination of Service and shall remain exercisable until the Expiration Date and (2) if the Value Condition is not satisfied on or prior to the date of such Termination of Service, the Option shall vest and shall remain exercisable until the Expiration Date when and only if the Value Condition is satisfied.

(ii)*Any Other Termination of Service.* In the event of the Participant's Termination of Service at any time prior to the Service Vesting Date for any reason (other than due to the Participant's death or Disability or termination by the Company without Cause or by the Participant for Good Reason), the Option shall be forfeited in its entirety as of the date of such termination without any payment to the Participant.

(b)Change in Control.

(i)If a Change in Control occurs before the Service Vesting Date (regardless of whether the Value Condition has been satisfied), the Option shall fully vest as of the date of such Change in Control; *provided*

that if prior to the date of such Change in Control, the Company or the acquirer requests in writing that the Participant continue to provide services to the Company (or the successor or surviving entity) for a specified period not to exceed 12 months after such Change in Control, the Option shall vest as of the earliest of (x) the last day of such requested period, (y) the Service Vesting Date or (z) the date, if any, of the Participant's Termination of Service by the Company (or the successor or surviving entity) without Cause, by the Participant for Good Reason or due to the Participant's death or Disability (such earliest date, the "Change in Control Vesting Date"). The Option shall be forfeited in its entirety without any payment to the Participant upon his or her Termination of Service by the Company (or the successor or surviving entity) for Cause or by the Participant without Good Reason at any time prior to the Change in Control Vesting Date.

(A) If, an accordance with Section 2(b)(i) above the Participant is not requested to continue to provide services and the Option vests as of the date of the Change in Control, the Option shall be canceled in consideration of the full acceleration of the Option and, at the Participant's election pursuant to such procedures as the Committee determines, (1) a cash payment in an amount equal to the Intrinsic Value of the Option (which may be equal to but not less than zero), which, if in excess of zero, shall be payable upon the effective date of such Change in Control, or (2) an option to purchase shares of the common stock of, as applicable, the acquirer, the surviving entity or the ultimate parent thereof (the Intrinsic Value of which option as of immediately following such Change in Control shall equal the Intrinsic Value of the Option immediately prior to such Change in Control). Notwithstanding the Participant's election pursuant to the preceding sentence, the Company's Chief Executive Officer may determine that all or a portion of the Option shall be treated in accordance with either of clauses (1) or (2) of the preceding sentence; *provided* that such treatment is substantially similar to the treatment applicable to the options to purchase Shares then held by other participants generally.

(B) If, an accordance with Section 2(b)(ii) above the Participant is requested to continue to provided services and the Option does not vest as of the date of the Change in Control, the Option shall be assumed, converted or replaced in connection with the Change in Control on an equivalent basis by the acquirer, successor or surviving entity.

(ii) If a Change in Control occurs on or after the Service Vesting Date (regardless of whether the Value Condition has been satisfied), the Option shall fully vest as of the date of such Change in

Control and the Option shall be canceled in consideration of the full acceleration of the Option and, at the Participant's election pursuant to such procedures as the Committee determines, (1) a cash payment in an amount equal to the Intrinsic Value of the Option (which may be equal to but not less than zero), which, if in excess of zero, shall be payable upon the effective date of such Change in Control, or (2) an option to purchase shares of the common stock of, as applicable, the acquirer, the surviving entity or the ultimate parent thereof (the Intrinsic Value of which option as of immediately following such Change in Control shall equal the Intrinsic Value of the Option immediately prior to such Change in Control). Notwithstanding the Participant's election pursuant to the preceding sentence, the Company's Chief Executive Officer may determine that all or a portion of the Option shall be treated in accordance with either of clauses (1) or (2) of the preceding sentence; *provided* that such treatment is substantially similar to the treatment applicable to the options to purchase Shares then held by other participants generally.

(c)For the avoidance of doubt, as used in this Section 2(b), "Intrinsic Value" means (i) the price or implied price per Share in a Change in Control over (ii) the exercise price of such Award multiplied by (iii) the number of Shares covered by the Option.

(d)Effect of Breaching Restrictive Covenants. Notwithstanding anything to the contrary in this Agreement, if at any time while the Option remains outstanding, the Participant breaches the restrictive covenants set forth in Participant's Employment Agreement, the Option shall be forfeited in its entirety.

Section 3. *Exercise of Option.*

(a)*Right to Exercise*. The Option shall be exercisable on or prior to the Expiration Date in accordance with the vesting schedule and applicable provisions set forth in this Agreement and the Plan.

(b)Method of Exercise.

(i)The Option shall be exercisable by delivery of an exercise notice in the form attached as Exhibit A (the "**Exercise Notice**") which shall state the election to exercise the Option, the number of Shares with respect to which the Option is being exercised, and such other representations and agreements as may be required by the Company; *provided* that the Option may be exercised with respect to whole Shares only. The Exercise Notice shall be accompanied by payment of the aggregate exercise price as to all exercised Shares. The Option shall be deemed to be exercised upon receipt by the Company of such fully executed Exercise Notice accompanied by the aggregate exercise price and the satisfaction of any tax withholding requirements.

(ii)No Shares shall be issued pursuant to the exercise of an Option unless such issuance and such exercise comply with all applicable laws and regulations. Assuming such compliance, for income tax purposes the Shares shall be considered transferred to the Participant on the date on which the Option is exercised with respect to such Shares.

(c)*Method of Payment*. Payment of the aggregate exercise price shall be made by any of the following, or a combination thereof, at the election of the Participant:

(i)cash or check;

(ii)if there is a public market for the Shares at such time, subject to such requirements as may be imposed by the Committee, through the delivery of irrevocable instructions to a broker to sell Shares obtained upon the exercise of the Option and to deliver promptly to the Company an amount out of the proceeds of such sale equal to the aggregate exercise price for the Shares being purchased; or

(iii)by any other method acceptable to the Committee.

(d)*Transferability*. The Option may not be assigned, sold, transferred or otherwise be subject to alienation by the Participant other than by will; provided, that, the designation of a beneficiary shall not constitute an assignment, sale, transfer or alienation.

(e)*Withholding*. No Shares will be issued pursuant to the exercise of this Option unless and until the Participant shall have remitted to the Company an amount sufficient to satisfy any federal, state or local withholding tax requirements, or shall have made other arrangements satisfactory to the Company with respect to such taxes. The Participant may elect that all or any part of such withholding requirement be satisfied by retention by the Company of a portion of the Shares purchased upon exercise of this Option. If such election is made, the Shares so retained shall be credited against such withholding requirement at the fair market value of the Shares on the date of exercise.

(f)*Effect of Breaching Restrictive Covenants*. Notwithstanding anything to the contrary in this Agreement, if at any time while the Award remains outstanding, the Participant breaches the Restrictive Covenants (as defined in Section 4(a) of this Agreement), the Option shall be forfeited in its entirety pursuant to Section 4.04 of the Employment Agreement.

Section 4. *Incorporation of Restrictive Covenants Set Forth in Employment Agreement*

(a)*Incorporation by Reference.* Company and Participant agree that the restrictive covenants set forth in Articles 11, 12, 13, 14, and 15 ("Restrictive

Covenants") and Section 4.04 of the Employment Agreement by and between the Company and Participant, dated November 3, 2014, are incorporated by reference herein as if they were part of this Agreement and set forth in it.

(b)*Agreement is Ancillary to the Employment Agreement.* The Parties acknowledge and agree that this Agreement is ancillary to the Employment Agreement, which the Parties are entering into at the same time.

(c)*Covenants are Reasonable and Related to the Company's Business Interests.* The Parties agree that the Restrictive Covenants are reasonable under the circumstances, necessary to protect the Company's business interests, goodwill, confidential information, and other business assets the Restrictive Covenants are intended to protect, and that any breach of such Restrictive Covenants would cause irreparable injury and harm to the Company. Participant understands that the Restrictive Covenants may limit Participant's ability to engage in certain businesses anywhere in the United States and outside of the United States during the Non-Compete Period, as defined in the Employment Agreement and whose definition is incorporated by reference herein, but acknowledges that Participant will receive sufficiently high remuneration and other benefits from the Company to justify such restrictions, and that Participant knowingly and voluntarily chooses to accept such limitations. Further, Participant acknowledges that his skills are such that he can be gainfully employed in non-competitive employment, and that the Restrictive Covenants will not prevent Participant from earning a living. Nevertheless, in the event the terms of Section 4 or the Restrictive Covenants shall be determined by any court of competent jurisdiction or arbitrator to be unenforceable by reason of their extending for too great a period of time or over too great a geographical area, or by reason of their being too extensive in any other respect, they will be interpreted to extend only over the maximum period of time for which they may be enforceable, over the maximum geographical area as to which they may be enforceable, or to the maximum extent in all other respects as to which they may be enforceable, all as determined by such court or arbitrator in such action.

(d)*Consideration is Reasonably Related to Interests Worthy of Protection.* The Parties acknowledge and agree that Participant has had access to, and shall continue to have access to, the Company's non-public, confidential, and proprietary information, as access to such information is essential to the performance of Participant's duties for the Company. Participant acknowledges and agrees that Participant is not otherwise entitled to the granting of the shares set forth in this Agreement, and that these shares provide Participant an interest in the Company that Participant would not otherwise have but for his agreement to the Restrictive Covenants. Participant also agrees that the shares are good and valuable consideration, which are intended to, and do, protect the Company's interests, and are reasonably related to the same. The Parties further acknowledge and agree that the Company has expended many resources, including time and money, in developing its confidential and proprietary information and goodwill,

and that the consideration and promises made herein, and in the Employment Agreement, are reasonably related to the protection of those interests, and also Participant's and the Company's interest in the short and long-term growth of the Company and in Participant's continued development and growth. Participant and the Company acknowledge and agree that said interests provide the Company a competitive advantage in the market place and that those interests are worthy of protection. Participant acknowledges that but for Participant's agreement to the Restrictive Covenants, Participant would not continue to receive access to the Company's non-public, confidential, and proprietary information, or be granted the shares, as set forth in this Agreement.

(e)*Reasonableness of Time, Scope, and Geography*. Participant hereby represents to the Company that he has read and understands, and agrees to be bound by, the terms of the Restrictive Covenants and Section 4. Participant acknowledges that the geographic scope and duration of the Restrictive Covenants are the result of arm's-length bargaining and are fair and reasonable in light of i) the nature and wide geographic scope of the Company's operations of, and in, the business, as defined in the Employment Agreement and whose definition is incorporated by reference herein, ii) Participant's level of control over and contact with the Company's operations of, and in, the Business in all locales in which it is conducted, iii) the geographic breadth in which the Company conducts the Business, and iv) the amount of consideration (including confidential information and trade secrets) that Participant is receiving from the Company. In consideration of the Company's promises herein, during the Non-Compete Period, Participant promises to disclose to the Company any employment, consulting, or other service relationship that Participant enters into after the termination of Participant's employment with the Company for any reason. Such disclosure shall be made within seven business days after Participant enters into such employment, consulting or other service relationship. Participant expressly consents to and authorizes the Company to disclose both the existence and terms of this Agreement to any future employer or recipient of Participant's services and to take any steps the Company deems necessary to enforce this Agreement.

(f)*Injunctive Relief*. Participant acknowledges and agrees that a breach of the Restrictive Covenants will cause irreparable damage to the Company and its Affiliates, as defined in the Employment Agreement and whose definition is incorporated by reference herein, and their goodwill, the exact amount of which will be difficult or impossible to ascertain, and that the remedies at law for any such breach will be inadequate. Accordingly, Participant agrees that in the event of a breach of any of the Restrictive Covenants, in addition to any other remedy which may be available at law or in equity, the Company will be entitled to equitable and injunctive relief. Participant and the Company agree that while any dispute or controversy arising under, or in connection with, the Employment Agreement, including a breach of the Restrictive Covenants, shall be settled exclusively by arbitration, conducted before an arbitrator in Houston, Texas in accordance with the National Rules for the Resolution of Employment

Disputes of the American Arbitration Association then in effect, the Company shall be entitled to seek a restraining order, injunction, or other equitable relief, and expedited discovery necessary for the proceedings to obtain said equitable or injunctive relief, in order to prevent or cease any violation or continuation of any violation of the provisions of the Restrictive Covenants. Participant consents that such restraining order or injunction may be granted without requiring the Company to post a bond larger than $500. Participant also agrees that waiver shall not be a defense to the Company's invocation of the Employment Agreement's arbitration clause subsequent to any proceeding to obtain the equitable or injunctive relief described under Section 4 and in the Employment Agreement. Further, for purposes of obtaining said equitable or injunctive relief, Participant consents to the personal jurisdiction and venue of any Texas State court or United States Court located in Harris County, Texas.

(g)*Choice of Law, Jurisdiction, Venue for Suits to Enforce Restrictive Covenants*. The Restrictive Covenants and *only* Section 4 of this Agreement shall be governed by, and construed in accordance with the laws of the State of Texas. With respect to any claim or dispute related to or arising under, or in relation to, the Restrictive Covenants and Section 4, including, but not limited to, suits seeking equitable and injunctive relief described in the Employment Agreement, Participant and the Company hereby consent to the exclusive jurisdiction, forum and venue of the state and federal courts located in Harris County, Texas.

Section 5. *Miscellaneous Provisions*.

(a)*Notices*. All notices, requests and other communications under this Agreement shall be in writing and shall be delivered in person (by courier or otherwise), mailed by certified or registered mail, return receipt requested, or sent by facsimile transmission, as follows:

if to the Company, to:

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
Attention: General Counsel
Facsimile: 713-579-9184

if to the Participant, to the address that the Participant most recently provided to the Company,

or to such other address or facsimile number as such party may hereafter specify for the purpose by notice to the other parties hereto. All such notices, requests

and other communications shall be deemed received on the date of receipt by the recipient thereof if received prior to 5:00 p.m. on a business day in the place of receipt. Otherwise, any such notice, request or communication shall be deemed received on the next succeeding business day in the place of receipt.

(b)*Entire Agreement*. This Agreement, the Plan, and any other agreements, schedules, exhibits and other documents referred to herein or therein, constitute the entire agreement and understanding between the parties in respect of the subject matter hereof and supersede all prior and contemporaneous arrangements, agreements and understandings, both oral and written, whether in term sheets, presentations or otherwise, between the parties with respect to the subject matter hereof.

(c)*Amendment; Waiver*. No amendment or modification of any provision of this Agreement shall be effective unless signed in writing by or on behalf of the Company and the Participant, except that the Company may amend or modify this Agreement without the Participant's consent in accordance with the provisions of the Plan or as otherwise set forth in this Agreement. No waiver of any breach or condition of this Agreement shall be deemed to be a waiver of any other or subsequent breach or condition whether of like or different nature. Any amendment or modification of or to any provision of this Agreement, or any waiver of any provision of this Agreement, shall be effective only in the specific instance and for the specific purpose for which made or given.

(d)*Assignment*. Neither this Agreement nor any right, remedy, obligation or liability arising hereunder or by reason hereof shall be assignable by the Participant.

(e)*Successors and Assigns; No Third Party Beneficiaries*. This Agreement shall inure to the benefit of and be binding upon the Company and the Participant and their respective heirs, successors, legal representatives and permitted assigns. Nothing in this Agreement, expressed or implied, is intended to confer on any person other than the Company and the Participant, and their respective heirs, successors, legal representatives and permitted assigns, any rights, remedies, obligations or liabilities under or by reason of this Agreement.

(f)*Counterparts*. This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

(g)*Participant Undertaking*. The Participant agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable to carry out or give effect to any of the obligations or restrictions imposed on either the Participant or the Option pursuant to the provisions of this Agreement.

(h)*Plan*. The Participant acknowledges and understands that material definitions and provisions concerning the Option and the Participant's rights and obligations with respect thereto are set forth in the Plan. The Participant has read carefully, and understands, the provisions of the Plan.

(i)*Governing Law*. The Agreement shall be governed by the laws of the State of Delaware, without application of the conflicts of law principles thereof.

(j)*No Right to Continued Service*. The granting of the Option evidenced hereby and this Agreement shall impose no obligation on the Company or any Affiliate to continue the service of the Participant and shall not lessen or affect the right that the Company or any Affiliate may have to terminate the service of such Participant.

(k)*Jurisdiction*. The parties hereto agree that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Agreement or the transactions contemplated hereby (whether brought by any party or any of its affiliates or against any party or any of its affiliates) shall be brought in the Delaware Chancery Court or, if such court shall not have jurisdiction, any federal court located in the State of Delaware or other Delaware state court, and each of the parties hereby irrevocably consents to the jurisdiction of such courts (and of the appropriate appellate courts therefrom) in any such suit, action or proceeding and irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such court or that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum. Process in any such suit, action or proceeding may be served on each party anywhere in the world, whether within or without the jurisdiction of any such court. Without limiting the foregoing, each party agrees that service of process on such party as provided in Section 5(a) shall be deemed effective service of process on such party.

(l)*WAIVER OF JURY TRIAL*. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

COBALT INTERNATIONAL ENERGY, INC.

By: ____________________________

Name:

Title:

By: ____________________________

Name: [Full Name]

EXHIBIT A
COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN
OPTION EXERCISE NOTICE

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, Texas 77024
Attention: [Secretary]

1. Exercise of Option. Effective as of today, (date), the undersigned ("**Participant**") hereby elects to exercise Participant's option to purchase shares of the common stock (the "**Shares**") of Cobalt International Energy, Inc. (the "**Company**") under and pursuant to the Long Term Incentive Plan (the "**Plan**") and the Non-Qualified Stock Option Award Agreement dated (the "**Award Agreement**"). Unless otherwise defined herein, the terms defined in the Plan and Award Agreement shall have the same defined meanings in this Exercise Notice.

2. Delivery of Payment. Participant herewith delivers to the Company the full aggregate exercise price of the Shares, as set forth in the Award Agreement.

3. Representations of Participant. Participant acknowledges that Participant has received, read and understood the Award Agreement and the Plan, and agrees to abide by and be bound by their terms and conditions.

4. Rights as Shareholder. Until the issuance of the Shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company or as otherwise determined by the Committee), no right to vote or receive dividends or any other rights as a shareholder shall exist with respect to the Shares that are subject to the Option, notwithstanding the exercise of the Option. The Shares shall be issued to Participant as soon as practicable after the Option is exercised. No adjustment shall be made for a dividend or other right for which the record date is prior to the date of issuance.

5. Tax Consultation. Participant understands that Participant may have a tax liability as a result of Participant's purchase or disposition of the Shares. Participant represents that Participant has consulted with any tax consultants Participant deems advisable in connection with the purchase or disposition of the Shares and that Participant is not relying on the Company for any tax advice.

6. Successors and Assigns. The Company may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Company. Subject to the restrictions on transfer herein set forth, this Exercise Notice shall be binding upon Participant and his or her heirs, executors, administrators, successors and assigns.

7. Interpretation. Any dispute regarding the interpretation of this Exercise Notice shall be submitted by Participant or by the Company forthwith to the Compensation Committee of the Board of Directors of the Company (the "**Committee**"). The resolution of such a dispute by the Committee shall be final and binding on all parties.

8. Governing Law. This Exercise Notice is governed by the internal substantive laws but not the choice of law rules, of the State of Delaware.

9. Entire Agreement. The Plan and the Award Agreement are incorporated herein by reference, and together with this Exercise Notice constitute the entire agreement of the parties with respect to the subject matter hereof and supersede in their entirety all prior undertakings and agreements of the Company and Participant with respect to the subject matter hereof.

Submitted by:	Accepted by:
PARTICIPANT:	COBALT INTERNATIONAL ENERGY, INC.
	By:
Signature	Name:
[Full Name]	
Residence Address	
	Date Received

Exhibit 10.38

COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN

Stock Appreciation Right Award Agreement
[Year] Grant

You have been granted a stock appreciation right (the "**SAR**") that represents a right to acquire shares of Cobalt International Energy, Inc. (this "**Award**") on the following terms and subject to the provisions of Attachment A and the Cobalt International Energy, Inc. Long Term Incentive Plan (the "**Plan**"). Unless defined in this Award Agreement (including Attachment A, this "**Agreement**"), capitalized terms will have the meanings assigned to them in the Plan. In the event of a conflict among the provisions of the Plan, this Agreement and any descriptive materials provided to you, the provisions of the Plan will prevail.

Participant	[Name]
Number of Shares Subject to the SAR	[Number] Shares
Grant Price per Share	$[Number]
Grant Date	[Date]
Expiration Date	[Date]
Vesting	Subject to Section 2 of Attachment A, the SAR shall vest with respect to one-third (1/3) of the underlying Shares on each of: [Date], [Date] and [Date] if the Participant does not experience a Termination of Service at any time prior to the applicable scheduled vesting date.

Attachment A

Stock Appreciation Right Award Agreement
Terms and Conditions

Grant to: [Name]

Section 1. *Grant of Award.* Subject to the terms and conditions of the Plan and this Agreement, the Company hereby grants the SAR to the Participant on the Grant Date on the terms set forth on the cover page of this Agreement, as more fully described in this Attachment A. The SAR represents the right to acquire up to, but not exceeding in the aggregate, the number of Shares set forth on the cover page of this Agreement. This Award is granted under the Plan, which is incorporated herein by reference and made a part of this Agreement.

Section 2. *Vesting of Award.*

(a) Termination of Service.

(i) *Death or Disability*. In the event of the Participant's Termination of Service at any time due to the Participant's death or Disability, any unvested portion of the SAR shall fully vest as of the date of such termination and the SAR shall remain exercisable until the Expiration Date.

(ii) *Termination for Cause*. In the event of the Participant's Termination of Service by the Company for Cause, any unvested portion of the SAR and any vested portion of the SAR not yet exercised shall be forfeited in its entirety as of the date of such termination without any payment to the Participant.

(iii) *Resignation by the Participant*. In the event of the Participant's Termination of Service at any time by the Participant for any reason, any unvested portion of the SAR shall be forfeited in its entirety as of the date of such termination without any payment to the Participant and any vested portion of the SAR shall remain exercisable until the Expiration Date.

(iv) *Termination without Cause*. In the event of the Participant's Termination of Service at any time by the Company without Cause, any unvested portion of the SAR shall be forfeited in its entirety as of the date of such termination without any payment to the Participant and any vested portion of the SAR shall remain exercisable until the earlier of (i) 90 days following such Termination of Service and (ii) the Expiration Date.

(b)*Change in Control*. If a Change in Control occurs at any time, the SAR shall be canceled in consideration of the full acceleration value of the SAR and, at the Participant's election pursuant to such procedures as the Committee determines, (i) a cash payment in an amount equal to the Intrinsic Value of the SAR (which may be equal to but not less than zero), which, if in excess of zero, shall be payable upon the effective date of such Change in Control, or (ii) a stock appreciation right to acquire shares of the common stock of, as applicable, the acquirer, the surviving entity or the ultimate parent thereof (the Intrinsic Value of which stock appreciation right as of immediately following such Change in Control shall equal the Intrinsic Value of the SAR immediately prior to such Change in Control). Notwithstanding the Participant's election pursuant to the preceding sentence, the Company's Chief Executive Officer may determine that all or a portion of the SAR shall be treated in accordance with either of clauses (i) or (ii) of the preceding sentence; *provided* that such treatment is substantially similar to the treatment applicable to the stock appreciation rights to acquire Shares then held by other participants generally.

Section 3. *Exercise of SAR.*

(a)*Right to Exercise*. The SAR shall be exercisable on or prior to the Expiration Date in accordance with the vesting schedule and applicable provisions set forth in this Agreement and the Plan.

(b)Method of Exercise.

(i)The vested portion of the SAR shall be exercisable by delivery of an exercise notice in the form attached as Exhibit A (the "**Exercise Notice**") which shall state the election to exercise the SAR, the number of Shares with respect to which the SAR is being exercised, and such other representations and agreements as may be required by the Company; *provided* that the SAR may be exercised with respect to whole Shares only. The SAR shall be deemed to be exercised upon receipt by the Company of such fully executed Exercise Notice and the satisfaction of any tax withholding requirements.

(ii)Upon exercise of the SAR, the Company shall deliver to the Participant, at the Company's discretion, (i) Shares issued in the Participant's name for the number of Shares, to the nearest number of whole Shares, (ii) cash or (iii) a combination of Shares and cash, which represent the excess (if any) of the Fair Market Value of the Shares underlying the portion of the SAR that is being exercised on the date of exercise over the aggregate exercise price of such Shares.

(iii)No Shares shall be issued pursuant to the exercise of an SAR unless such issuance and such exercise comply with all applicable laws and regulations. Assuming such compliance, for income tax

purposes the Shares shall be considered transferred to the Participant on the date on which the SAR is exercised with respect to such Shares.

(c) *Transferability*. The SAR may not be assigned, sold, transferred or otherwise be subject to alienation by the Participant other than by will; provided, that, the designation of a beneficiary shall not constitute an assignment, sale, transfer or alienation.

(d) *Withholding*. No Shares or cash will be issued pursuant to the exercise of this SAR unless and until the Participant shall have remitted to the Company an amount sufficient to satisfy any federal, state or local withholding tax requirements, or shall have made other arrangements satisfactory to the Company with respect to such taxes. The Participant may elect that all or any part of such withholding requirement be satisfied by retention by the Company of a portion of the Shares and/or cash acquired upon exercise of the SAR. If such election is made, the Shares and/or cash so retained shall be credited against such withholding requirement at the fair market value of the Shares on the date of exercise.

Section 4. *Miscellaneous Provisions*.

(a) *Notices*. All notices, requests and other communications under this Agreement shall be in writing and shall be delivered in person (by courier or otherwise), mailed by certified or registered mail, return receipt requested, or sent by facsimile transmission, as follows:

if to the Company, to:

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, TX 77024
Attention: General Counsel
Facsimile: 713-579-9184

if to the Participant, to the address that the Participant most recently provided to the Company,

or to such other address or facsimile number as such party may hereafter specify for the purpose by notice to the other parties hereto. All such notices, requests and other communications shall be deemed received on the date of receipt by the recipient thereof if received prior to 5:00 p.m. on a business day in the place of receipt. Otherwise, any such notice, request or communication shall be deemed received on the next succeeding business day in the place of receipt.

(b) *Entire Agreement*. This Agreement, the Plan, and any other agreements referred to herein and therein and any schedules, exhibits and other documents referred to herein or therein, constitute the entire agreement and

understanding between the parties in respect of the subject matter hereof and supersede all prior and contemporaneous arrangements, agreements and understandings, both oral and written, whether in term sheets, presentations or otherwise, between the parties with respect to the subject matter hereof.

(c)*Amendment; Waiver*. No amendment or modification of any provision of this Agreement shall be effective unless signed in writing by or on behalf of the Company and the Participant, except that the Company may amend or modify this Agreement without the Participant's consent in accordance with the provisions of the Plan or as otherwise set forth in this Agreement. No waiver of any breach or condition of this Agreement shall be deemed to be a waiver of any other or subsequent breach or condition whether of like or different nature. Any amendment or modification of or to any provision of this Agreement, or any waiver of any provision of this Agreement, shall be effective only in the specific instance and for the specific purpose for which made or given.

(d)*Assignment*. Neither this Agreement nor any right, remedy, obligation or liability arising hereunder or by reason hereof shall be assignable by the Participant.

(e)*Successors and Assigns; No Third Party Beneficiaries*. This Agreement shall inure to the benefit of and be binding upon the Company and the Participant and their respective heirs, successors, legal representatives and permitted assigns. Nothing in this Agreement, expressed or implied, is intended to confer on any person other than the Company and the Participant, and their respective heirs, successors, legal representatives and permitted assigns, any rights, remedies, obligations or liabilities under or by reason of this Agreement.

(f)*Counterparts*. This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

(g)*Participant Undertaking*. The Participant agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable to carry out or give effect to any of the obligations or restrictions imposed on either the Participant or this Award pursuant to the provisions of this Agreement.

(h)*Plan*. The Participant acknowledges and understands that material definitions and provisions concerning this Award and the Participant's rights and obligations with respect thereto are set forth in the Plan. The Participant has read carefully, and understands, the provisions of the Plan.

(i)*Governing Law*. The Agreement shall be governed by the laws of the State of Delaware, without application of the conflicts of law principles thereof.

(j)*No Right to Continued Service.* The granting of the Award evidenced hereby and this Agreement shall impose no obligation on the Company or any Affiliate to continue the service of the Participant and shall not lessen or affect the right that the Company or any Affiliate may have to terminate the service of such Participant.

(k)*Jurisdiction.* The parties hereto agree that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Agreement or the transactions contemplated hereby (whether brought by any party or any of its affiliates or against any party or any of its affiliates) shall be brought in the Delaware Chancery Court or, if such court shall not have jurisdiction, any federal court located in the State of Delaware or other Delaware state court, and each of the parties hereby irrevocably consents to the jurisdiction of such courts (and of the appropriate appellate courts therefrom) in any such suit, action or proceeding and irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such court or that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum. Process in any such suit, action or proceeding may be served on each party anywhere in the world, whether within or without the jurisdiction of any such court. Without limiting the foregoing, each party agrees that service of process on such party as provided in Section 5(a) shall be deemed effective service of process on such party.

(l) *WAIVER OF JURY TRIAL.* EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

COBALT INTERNATIONAL ENERGY, INC.

By: ______________________________

Name: Jeffrey A. Starzec

Title: Senior Vice President and General Counsel

____
[Participant]

EXHIBIT A
COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN
STOCK APPRECIATION RIGHT EXERCISE NOTICE

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, TX 77024
Attention: [Secretary]

1. Exercise of Stock Appreciation Right. Effective as of today, (date), the undersigned ("**Participant**") hereby elects to exercise Participant's stock appreciation right (the "**SAR**") with respect to shares of the common stock (the "**Shares**") of Cobalt International Energy, Inc. (the "**Company**") under and pursuant to the Long Term Incentive Plan (the "**Plan**") and the SAR Award Agreement dated (the "**Award Agreement**"). Unless otherwise defined herein, the terms defined in the Plan and Award Agreement shall have the same defined meanings in this Exercise Notice.

2. Representations of Participant. Participant acknowledges that Participant has received, read and understood the Award Agreement and the Plan, and agrees to abide by and be bound by their terms and conditions.

3. Rights as Shareholder. Until the issuance of the Shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company or as otherwise determined by the Committee), no right to vote or receive dividends or any other rights as a shareholder shall exist with respect to the Shares that are subject to the SAR, notwithstanding the exercise of the SAR. The Shares shall be issued to Participant as soon as practicable after the SAR is exercised. No adjustment shall be made for a dividend or other right for which the record date is prior to the date of issuance.

4. Tax Consultation. Participant understands that Participant may have a tax liability as a result of Participant's acquisition or disposition of the Shares underlying the SAR. Participant represents that Participant has consulted with any tax consultants Participant deems advisable in connection with the purchase or disposition of the Shares and that Participant is not relying on the Company for any tax advice.

5. Successors and Assigns. The Company may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Company. Subject to the

restrictions on transfer herein set forth, this Exercise Notice shall be binding upon Participant and his or her heirs, executors, administrators, successors and assigns.

6. Interpretation. Any dispute regarding the interpretation of this Exercise Notice shall be submitted by Participant or by the Company forthwith to the Compensation Committee of the Board of Directors of the Company (the "**Committee**"). The resolution of such a dispute by the Committee shall be final and binding on all parties.

7. Governing Law. This Exercise Notice is governed by the internal substantive laws but not the choice of law rules, of the State of Delaware.

8. Entire Agreement. The Plan and the Award Agreement are incorporated herein by reference, and together with this Exercise Notice constitute the entire agreement of the parties with respect to the subject matter hereof and supersede in their entirety all prior undertakings and agreements of the Company and Participant with respect to the subject matter hereof.

Submitted by:	Accepted by:
PARTICIPANT:	COBALT INTERNATIONAL ENERGY, INC.
	By:
Signature	Name:
	Title:
Residence Address	
	Date Received

Exhibit 10.39

COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN

Restricted Stock Unit Award Agreement
[Year] Grant

You have been granted an award of restricted stock units (this "**Award**") on the following terms and subject to the provisions of Attachment A and the Cobalt International Energy, Inc. Long Term Incentive Plan (the "**Plan**"). Unless defined in this Award Agreement (including Attachment A, this "**Agreement**"), capitalized terms will have the meanings assigned to them in the Plan. In the event of a conflict among the provisions of the Plan, this Agreement and any descriptive materials provided to you, the provisions of the Plan will prevail.

Participant	[Name]
Number of Shares Underlying Award	[Number] Shares (the "**RSU Shares**")
Grant Date	[Date]
Vesting	Subject to Section 4 and Section 5 of Attachment A, the Award shall vest with respect to one-third (1/3) of the underlying RSU Shares on each of: [Date], [Date] and [Date] (each, a "**Scheduled Vesting Date**") if the Participant does not experience a Termination of Service at any time prior to the applicable Scheduled Vesting Date

Attachment A

Restricted Stock Unit Award Agreement
Terms and Conditions

Grant to: [Name]

SECTION 1. *Grant of Award.* Subject to the terms and conditions of the Plan and this Agreement, the Company hereby grants this Award to the Participant on the Grant Date on the terms set forth on the cover page of this Agreement, as more fully described in this Attachment A. This Award is granted under the Plan, which is incorporated herein by this reference and made a part of this Agreement.

SECTION 2. *Conversion of Award.* The portion of this Award that vests on each applicable Scheduled Vesting Date will convert into, as determined by the Company, (i) RSU Shares, (ii) cash in an amount equal to the then Fair Market Value of the RSU Shares, or (iii) a combination of RSU Shares and cash, and will be distributed to the Participant on or as soon as practicable after such date, but in no event later than March 15th of the year following such date.

SECTION 3. *Dividend Equivalents.* If a dividend is paid on Shares during the period commencing on the Grant Date and ending on the date on which the RSU Shares or a cash payment in respect thereof are distributed to the Participant, the Participant shall be eligible to receive an amount equal to the amount of the dividend that the Participant would have received had the RSU Shares been distributed to the Participant as of the record date for which such dividend is paid; *it being understood* that no such amount shall be payable with respect to any RSU Shares that are forfeited. Such amount shall be paid to the Participant on the date on which the RSU Shares or a cash payment in respect thereof are distributed to the Participant in the same form (cash, Shares or other property) in which such dividend is paid to holders of Shares generally. Any Shares that the Participant is eligible to receive pursuant to this Section 3 are referred to herein as "**Dividend Shares**".

SECTION 4. *Termination of Service.*

(a)*Death or Disability.* In the event of the Participant's Termination of Service at any time due to the Participant's death or Disability, the Award shall fully vest as of the date of such termination. This Award will convert into RSU Shares or a cash payment in respect thereof and will be distributed to the Participant (or the Participant's estate) on or as soon as practicable after the date of such termination, but in no event later than March 15th of the year following such date.

(b)*Any Other Termination of Service.* In the event of the Participant's Termination of Service at any time for any reason (other than due to the

Participant's death or Disability), the then unvested portion of this Award will be forfeited in its entirety as of the date of such termination without any payment to the Participant.

(c) *Committee Discretion*. Notwithstanding the foregoing, in the event of the Participant's Termination of Service other than by the Company for Cause, the Committee may, in its sole discretion, accelerate the vesting or waive any term or condition of this Agreement, subject to such terms and conditions as the Committee deems appropriate, with respect to all or a portion of the Award.

SECTION 5. *Change in Control*. Upon a Change in Control, this Award (to the extent then unvested and not previously forfeited) will fully vest, and the RSU Shares (to the extent not yet distributed) will be distributed to the Participant on the effective date of the Change in Control.

SECTION 6. *Additional Terms and Conditions*.

(a) *Issuance of Shares*. Upon distribution of RSU Shares and, if applicable, any Dividend Shares, such Shares shall be evidenced by book-entry registration; *provided, however*, that the Committee may determine that such Shares shall be evidenced in such other manner as it deems appropriate, including the issuance of a stock certificate or certificates.

(b) *Stockholder Rights*. The Participant shall not have any rights of a stockholder, including voting rights, with respect to the Award until RSU Shares have been distributed to the Participant.

(c) *Transferability*. Unless and until RSU Shares and, if applicable, any Dividend Shares are distributed to the Participant, this Award shall not be assigned, sold, transferred or otherwise be subject to alienation by the Participant.

(d) *Section 409A*.

(i) If any provision of this Agreement fails to comply with Section 409A of the Code or the regulations or Treasury guidance promulgated thereunder, or would result in a recognition of income for United States federal income tax purposes with respect to any amount payable under this Agreement before the date of payment, or the imposition of interest or additional tax pursuant to Section 409A of the Code, the Company reserves the right to reform such provision; *provided* that the Company shall maintain, to the maximum extent practicable, the original intent of the applicable provision without violating the provisions of Section 409A of the Code.

(ii) Notwithstanding anything else in this Agreement, if the Board considers the Participant to be one of the Company's "specified employees" under Section 409A of the Code at the time of the Participant's Termination of Service, any distribution that otherwise

would be made to the Participant with respect to this Award as a result of such termination shall not be made until the date that is six months after such termination, except to the extent that earlier distribution would not result in the Participant's incurring interest or additional tax under Section 409A of the Code.

(e) *Withholding.* The Company may withhold any tax (or other governmental obligation) that becomes due with respect to the Award upon vesting and conversion (as applicable), or any dividend or distribution thereon, and the Participant shall make arrangements satisfactory to the Company to enable the Company to satisfy all such withholding requirements. Notwithstanding the foregoing, the Committee may permit, in its sole discretion, the Participant (at the Participant's election) to satisfy any such withholding requirement by transferring to the Company pursuant to such procedures as the Committee may require, effective as of the date on which a withholding obligation arises, a number of vested Shares owned and designated by the Participant having an aggregate fair market value as of such date that is equal to the minimum amount required to be withheld and/or cash in such amount. If the Committee permits the Participant (at the Participant's election) to satisfy any such withholding requirement pursuant to the preceding sentence, the Company shall remit to the Internal Revenue Service and appropriate state and local revenue agencies, for the credit of the Participant, an amount of cash withholding equal to the fair market value of the Shares and/or cash transferred to the Company as provided above.

SECTION 7. *Miscellaneous Provisions.*

(a) *Notices*. All notices, requests and other communications under this Agreement shall be in writing and shall be delivered in person (by courier or otherwise), mailed by certified or registered mail, return receipt requested, or sent by facsimile transmission, as follows:

if to the Company, to:

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, TX 77024
Attention: General Counsel
Facsimile: 713-579-9184

if to the Participant, to the address that the Participant most recently provided to the Company,

or to such other address or facsimile number as such party may hereafter specify for the purpose by notice to the other parties hereto. All such notices, requests and other communications shall be deemed received on the date of receipt by the

recipient thereof if received prior to 5:00 p.m. on a business day in the place of receipt. Otherwise, any such notice, request or communication shall be deemed received on the next succeeding business day in the place of receipt.

(b)*Entire Agreement*. This Agreement, the Plan, and any other agreements referred to herein and therein and any schedules, exhibits and other documents referred to herein or therein, constitute the entire agreement and understanding between the parties in respect of the subject matter hereof and supersede all prior and contemporaneous arrangements, agreements and understandings, both oral and written, whether in term sheets, presentations or otherwise, between the parties with respect to the subject matter hereof.

(c)*Amendment; Waiver*. No amendment or modification of any provision of this Agreement shall be effective unless signed in writing by or on behalf of the Company and the Participant, except that the Company may amend or modify this Agreement without the Participant's consent in accordance with the provisions of the Plan or as otherwise set forth in this Agreement. No waiver of any breach or condition of this Agreement shall be deemed to be a waiver of any other or subsequent breach or condition whether of like or different nature. Any amendment or modification of or to any provision of this Agreement, or any waiver of any provision of this Agreement, shall be effective only in the specific instance and for the specific purpose for which made or given.

(d)*Assignment*. Neither this Agreement nor any right, remedy, obligation or liability arising hereunder or by reason hereof shall be assignable by the Participant.

(e)*Successors and Assigns; No Third Party Beneficiaries*. This Agreement shall inure to the benefit of and be binding upon the Company and the Participant and their respective heirs, successors, legal representatives and permitted assigns. Nothing in this Agreement, expressed or implied, is intended to confer on any person other than the Company and the Participant, and their respective heirs, successors, legal representatives and permitted assigns, any rights, remedies, obligations or liabilities under or by reason of this Agreement.

(f)*Counterparts*. This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

(g)*Participant Undertaking*. The Participant agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable to carry out or give effect to any of the obligations or restrictions imposed on either the Participant or this Award pursuant to the provisions of this Agreement.

(h)*Plan*. The Participant acknowledges and understands that material definitions and provisions concerning this Award and the Participant's rights and

obligations with respect thereto are set forth in the Plan. The Participant has read carefully, and understands, the provisions of the Plan.

(i) *Governing Law*. The Agreement shall be governed by the laws of the State of Delaware, without application of the conflicts of law principles thereof.

(j) *No Right to Continued Service*. The granting of the Award evidenced hereby and this Agreement shall impose no obligation on the Company or any Affiliate to continue the service of the Participant and shall not lessen or affect the right that the Company or any Affiliate may have to terminate the service of such Participant.

(k) *Jurisdiction*. The parties hereto agree that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Agreement or the transactions contemplated hereby (whether brought by any party or any of its affiliates or against any party or any of its affiliates) shall be brought in the Delaware Chancery Court or, if such court shall not have jurisdiction, any federal court located in the State of Delaware or other Delaware state court, and each of the parties hereby irrevocably consents to the jurisdiction of such courts (and of the appropriate appellate courts therefrom) in any such suit, action or proceeding and irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such court or that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum. Process in any such suit, action or proceeding may be served on each party anywhere in the world, whether within or without the jurisdiction of any such court. Without limiting the foregoing, each party agrees that service of process on such party as provided in Section 7(a) shall be deemed effective service of process on such party.

(l) *WAIVER OF JURY TRIAL*. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

COBALT INTERNATIONAL ENERGY, INC.

By: ______________________________

Name: Jeffrey A. Starzec

Title: Executive Vice President and General Counsel

____

[Participant]

Exhibit 10.40

COBALT INTERNATIONAL ENERGY, INC.
LONG TERM INCENTIVE PLAN

Restricted Stock Award Agreement
[Year] Grant

You have been granted restricted stock (this "**Award**") on the following terms and subject to the provisions of Attachment A and the Cobalt International Energy, Inc. Long Term Incentive Plan (the "**Plan**"). Unless defined in this Award Agreement (including Attachment A, this "**Agreement**"), capitalized terms will have the meanings assigned to them in the Plan. In the event of a conflict among the provisions of the Plan, this Agreement and any descriptive materials provided to you, the provisions of the Plan will prevail.

Participant	[Name]
Number of Shares Underlying Award	[Number] Shares (to the extent not vested as of any applicable date, the "**Restricted Shares**")
Grant Date	[Date]
Vesting	Subject to Section 3 of Attachment A, the Award shall vest with respect to one-third (1/3) of the underlying Restricted Shares on each of: [Date], [Date] and [Date] if the Participant does not experience a Termination of Service at any time prior to the applicable scheduled vesting date.

Attachment A

Restricted Stock Award Agreement
Terms and Conditions

Grant to: [Name]

Section 1. *Grant of Restricted Stock Award.* Subject to the terms and conditions of the Plan and this Agreement, the Company hereby grants Restricted Stock to the Participant on the Grant Date on the terms set forth on the cover page of this Agreement, as more fully described in this Attachment A. This Award is granted under the Plan, which is incorporated herein by this reference and made a part of this Agreement.

Section 2. *Issuance of Shares.*

(a)The Restricted Shares shall be evidenced by book-entry registration; *provided, however*, that the Committee may determine that the Restricted Shares shall be evidenced in such other manner as it deems appropriate, including the issuance of a stock certificate or certificates. In the event that any stock certificate is issued in respect of the Restricted Shares, such certificate shall (i) be registered in the name of the Participant, (ii) bear an appropriate legend referring to the terms, conditions and restrictions applicable to the Restricted Shares and (iii) be held in custody by the Company.

(b)*Voting Rights*. The Participant shall have voting rights with respect to the Restricted Shares.

(c)*Dividends*. All cash and other dividends and distributions, if any, that are paid with respect to any Restricted Shares shall be withheld by the Company and paid to the Participant, without interest, only when, and if, the Restricted Shares become vested in accordance with this Agreement.

(d)*Transferability*. Unless and until the Restricted Shares become vested in accordance with this Agreement, the Restricted Shares shall not be assigned, sold, transferred or otherwise be subject to alienation by the Participant.

(e)*Section 83(b) Election*. If the Participant chooses, the Participant may make an election under Section 83(b) of the Code with respect to the Restricted Shares, which would cause the Participant currently to recognize income for U.S. federal income tax purposes in an amount equal to the excess (if any) of the fair market value of the Restricted Shares (determined as of the Grant Date) over the amount, if any, that the Participant paid for the Restricted Shares, which excess will be subject to U.S. federal income tax. The form for making a Section 83(b) election is attached as Attachment B. **The Participant acknowledges that (i) the Participant is solely responsible for the decision whether or not to make a Section 83(b) election, and the Company is not**

making any recommendation with respect thereto, (ii) it is his or her sole responsibility to timely file the Section 83(b) election within 30 days after the Grant Date, if the Participant decides to make such election, and (iii) if the Participant does not make a valid and timely Section 83(b) election, the Participant will be required to recognize ordinary income at the time of vesting on any future appreciation on the Restricted Shares.

(f) *Withholding Requirements*. The Company may withhold any tax (or other governmental obligation) that becomes due with respect to the Restricted Shares (or any dividend or distribution thereon), and the Participant shall make arrangements satisfactory to the Company to enable the Company to satisfy all such withholding requirements. Notwithstanding the foregoing, the Committee may permit, in its sole discretion, the Participant (at the Participant's election) to satisfy any such withholding requirement by transferring to the Company pursuant to such procedures as the Committee may require, effective as of the date on which a withholding obligation arises, a number of vested Shares owned and designated by the Participant having an aggregate fair market value as of such date that is equal to the minimum amount required to be withheld. If the Committee permits the Participant (at the Participant's election) to satisfy any such withholding requirement pursuant to the preceding sentence, the Company shall remit to the Internal Revenue Service and appropriate state and local revenue agencies, for the credit of the Participant, an amount of cash withholding equal to the fair market value of the Shares transferred to the Company as provided above.

Section 3. *Vesting of Restricted Shares*.

(a) *Termination of Service*.

(i) *Death or Disability*. In the event of the Participant's Termination of Service at any time due to the Participant's death or Disability, the Restricted Shares shall fully vest as of the date of such termination.

(ii) *Any Other Termination of Service*. In the event of the Participant's Termination of Service at any time for any reason (other than due to the Participant's death or Disability), the Restricted Shares shall be forfeited in their entirety as of the date of such termination without any payment to the Participant.

Notwithstanding the foregoing, in the event of the Participant's Termination of Service other than by the Company for Cause, the Committee may, in its sole discretion, accelerate the vesting or waive any term or condition of this Agreement, subject to such terms and conditions as the Committee deems appropriate, with respect to all or a portion of the Restricted Shares.

(b) *Change in Control*. If a Change in Control occurs at any time, the Restricted Shares shall fully vest as of the date of such Change in Control.

(c)*Effect of Vesting*. Subject to the provisions of this Agreement, upon the vesting of Restricted Shares, the restrictions under this Award with respect to such Shares shall lapse, and subject to any applicable Lock Up Agreement, or requirement to comply with non-competition covenants, such Shares shall be fully assignable, saleable and transferable by the Participant, and the Company shall deliver such Shares, along with any dividends and other distributions that were paid with respect to such Shares but withheld pending vesting, to the Participant. Subject to any applicable Lock Up Agreement or requirement to comply with non-competition covenants, such Shares shall be delivered by transfer to the Depository Trust Company for the benefit of the Participant or by delivery of a stock certificate registered in the Participant's name.

Section 4. *Miscellaneous Provisions*.

(a)*Notices*. All notices, requests and other communications under this Agreement shall be in writing and shall be delivered in person (by courier or otherwise), mailed by certified or registered mail, return receipt requested, or sent by facsimile transmission, as follows:

if to the Company, to:

Cobalt International Energy, Inc.
Cobalt Center
920 Memorial City Way, Suite 100
Houston, TX 77024
Attention: General Counsel
Facsimile: 713-579-9184

if to the Participant, to the address that the Participant most recently provided to the Company,

or to such other address or facsimile number as such party may hereafter specify for the purpose by notice to the other parties hereto. All such notices, requests and other communications shall be deemed received on the date of receipt by the recipient thereof if received prior to 5:00 p.m. on a business day in the place of receipt. Otherwise, any such notice, request or communication shall be deemed received on the next succeeding business day in the place of receipt.

(b)*Entire Agreement*. This Agreement, the Plan, and any other agreements referred to herein and therein and any schedules, exhibits and other documents referred to herein or therein, constitute the entire agreement and understanding between the parties in respect of the subject matter hereof and supersede all prior and contemporaneous arrangements, agreements and

understandings, both oral and written, whether in term sheets, presentations or otherwise, between the parties with respect to the subject matter hereof.

(c) *Amendment; Waiver*. No amendment or modification of any provision of this Agreement shall be effective unless signed in writing by or on behalf of the Company and the Participant, except that the Company may amend or modify the Agreement without the Participant's consent in accordance with the provisions of the Plan or as otherwise set forth in this Agreement. No waiver of any breach or condition of this Agreement shall be deemed to be a waiver of any other or subsequent breach or condition whether of like or different nature. Any amendment or modification of or to any provision of this Agreement, or any waiver of any provision of this Agreement, shall be effective only in the specific instance and for the specific purpose for which made or given.

(d) *Assignment*. Neither this Agreement nor any right, remedy, obligation or liability arising hereunder or by reason hereof shall be assignable by the Participant.

(e) *Successors and Assigns; No Third Party Beneficiaries*. This Agreement shall inure to the benefit of and be binding upon the Company and the Participant and their respective heirs, successors, legal representatives and permitted assigns. Nothing in this Agreement, expressed or implied, is intended to confer on any Person other than the Company and the Participant, and their respective heirs, successors, legal representatives and permitted assigns, any rights, remedies, obligations or liabilities under or by reason of this Agreement.

(f) *Counterparts*. This Agreement may be signed in any number of counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

(g) *Participant Undertaking*. The Participant agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable to carry out or give effect to any of the obligations or restrictions imposed on either the Participant or the Restricted Shares pursuant to the provisions of this Agreement.

(h) *Plan*. The Participant acknowledges and understands that material definitions and provisions concerning the Restricted Shares and the Participant's rights and obligations with respect thereto are set forth in the Plan. The Participant has read carefully, and understands, the provisions of the Plan.

(i) *Governing Law*. The Agreement shall be governed by the laws of the State of Delaware, without application of the conflicts of law principles thereof.

(j) *Jurisdiction*. The parties hereto agree that any suit, action or proceeding seeking to enforce any provision of, or based on any matter arising out of or in connection with, this Agreement or the transactions contemplated hereby (whether brought by any party or any of its affiliates or against any party or any of its affiliates) shall be brought in the Delaware Chancery Court or, if such court shall not have jurisdiction, any federal court located in the State of Delaware or other Delaware state court, and each of the parties hereby irrevocably consents to the jurisdiction of such courts (and of the appropriate appellate courts therefrom) in any such suit, action or proceeding and irrevocably waives, to the fullest extent permitted by law, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding in any such court or that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum. Process in any such suit, action or proceeding may be served on each party anywhere in the world, whether within or without the jurisdiction of any such court. Without limiting the foregoing, each party agrees that service of process on such party as provided in Section 4(a) shall be deemed effective service of process on such party.

(k) *WAIVER OF JURY TRIAL*. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATED TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first written above.

COBALT INTERNATIONAL ENERGY, INC.

By: ______________________________

Name: Jeffrey A. Starzec

Title: Senior Vice President and General Counsel

____

[Participant]

Attachment B

SECTION 83(b) ELECTION

This statement is being made under Section 83(b) of the Internal Revenue Code, pursuant to Treas. Reg. Section 1.83-2.

(1) The taxpayer performing the services is:

Name:

Address:

Social Security Number:

(2) The property with respect to which the election is being made is shares (the "**Restricted Shares**") of common stock, par value $.01 per share, of Cobalt International Energy, Inc. (the "**Company**")

(3) The Restricted Shares were transferred on .

(4) The taxable year in which the election is being made is the calendar year .

(5) The Restricted Shares are not transferable and are subject to a substantial risk of forfeiture within the meaning of Section 83(c)(1) of the Internal Revenue Code until and unless specified conditions are satisfied or a specified event occurs, in each case as set forth in the Company's Long Term Incentive Plan and the Restricted Stock Award Agreement pursuant to which the Restricted Shares were issued.

(6) The fair market value of the Restricted Shares at the time of transfer (determined without regard to any restriction other than a restriction which by its terms will never lapse) is $ per share.

(7) The amount paid by the taxpayer for the Restricted Shares is $ per share.

(8) A copy of this statement has been furnished to the Company, for whom the taxpayer will be performing services underlying the transfer of the Restricted Shares.

(9) This statement is executed on .

Spouse (if any)	Taxpayer

This statement must be filed with the Internal Revenue Service Center with which you filed your last U.S. federal income tax return within 30 days after the grant date of the Restricted Stock Award Agreement. This filing should be made by registered or certified mail, return receipt requested. You are also required to (i) deliver a copy of this statement to the Company and (ii) attach a copy of this statement to your federal income tax return for the taxable year that includes the grant date (and may also be required to attach a copy of this statement to your state income tax return for such year). You should also retain a copy of this statement for your records.

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Exhibit 12.1

Cobalt International Energy, Inc.

Computation of Ratios of Earnings to Fixed Charges

	Year Ended December 31, 2014	2013	2012	2011	2010
	($ in thousands)				
Fixed Charges:					
Interest expense	$ 74,768	$ 65,376	$ 3,140		
Capitalized interest	58,458	17,699	—		
Total	$ 133,226	$ 83,075	$ 3,140		
Earnings:					
Pretax (loss) income from continuing operations	(510,763)	$ (589,024)	$ (282,999)	$ (133,637)	$ (136,476)
Fixed charges	133,226	83,075	3,140	—	—
Less: Interest capitalized in current period	(58,458)	(17,699)	—	—	—
Total	(435,995)	$ (523,648)	$ (279,859)	$ (133,637)	$ (136,476)
Ratio of Earnings to Fixed Charges	—	—	—	—	—
Insufficient coverage	$ 569,221	$ 606,723	$ 282,999	N/A	N/A

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Exhibit 21.1

Cobalt International Energy, Inc. Subsidiary List

Subsidiary	Jurisdiction of Formation
Cobalt International Energy GP, LLC	Delaware
Cobalt International Energy, L.P.	Delaware
Cobalt GOM LLC	Delaware
Cobalt GOM #1 LLC	Delaware
Cobalt GOM #2 LLC	Delaware
Cobalt International Energy Overseas Ltd.	Cayman Islands
Cobalt International Energy Angola Ltd.	Cayman Islands
CIE Angola Block 9 Ltd.	Cayman Islands
CIE Angola Block 20 Ltd.	Cayman Islands
CIE Angola Block 21 Ltd.	Cayman Islands
Cobalt International Energy Gabon Ltd.	Cayman Islands
CIE Gabon Diaba Ltd.	Cayman Islands
CIE Mexico, LLC.	Delaware
CIE Mexico 2, LLC.	Delaware
Cobalt Energía de México, S. de R.L..	Mexico

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-164624) pertaining to the Cobalt International Energy, Inc. Non-Employee Directors Compensation Plan and the Cobalt International Energy, Inc. Non-Employee Directors Deferral Plan, Form S-8 (No. 333-163883) pertaining to the Cobalt International Energy, Inc. Long Term Incentive Plan, and Form S-3 (No. 333-193117) related to the Prospectus of Cobalt International Energy, Inc. for the registration of common stock, preferred stock, debt securities, warrants, purchase contracts and units, respectively, of our reports dated February 23, 2015, with respect to the consolidated financial statements of Cobalt International Energy, Inc., and the effectiveness of internal control over financial reporting of Cobalt International Energy, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2014.

/s/ Ernst & Young LLP

Houston, Texas
February 23, 2015

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Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the reference of our firm and to the use of our report effective December 31, 2014, dated January 22, 2015, in the Cobalt International Energy, Inc. Annual Report on Form 10-K for the year ended December 31, 2014, to be filed with the U. S. Securities and Exchange Commission on or about February 23, 2015.

We hereby further consent to the incorporation by reference in the Registration Statements on (i) Form S-8 (file no. 333-163883), (ii) Form S-8 (file no. 333-164624), and (iii) Form S-3 (file no. 333-193117) of such information and in any related prospectus, including any reference to our firm under the heading "Experts" in such prospectus.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ G. LANCE BINDER

G. Lance Binder, P.E.
Executive Vice President

Dallas, Texas
February 23, 2015

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EXHIBIT 31.1

Certification by Joseph H. Bryant
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Joseph H. Bryant, certify that:

1. I have reviewed this annual report on Form 10-K of Cobalt International Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2015

/s/ JOSEPH H. BRYANT

Joseph H. Bryant
Chairman of the Board and Chief Executive Officer

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EXHIBIT 31.2

Certification by John P. Wilkirson
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, John P. Wilkirson, certify that:

1. I have reviewed this annual report on Form 10-K of Cobalt International Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2015

/s/ JOHN P. WILKIRSON

John P. Wilkirson
Chief Financial Officer and Executive Vice President

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EXHIBIT 32.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Cobalt International Energy, Inc. (the "Company") for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Joseph H. Bryant, as Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(i) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2015

/s/ JOSEPH H. BRYANT

Joseph H. Bryant
Chairman of the Board of Directors and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Cobalt International Energy, Inc. and will be retained by Cobalt International Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

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EXHIBIT 32.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of Cobalt International Energy, Inc. (the "Company") for the year ended December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), John P. Wilkirson, as Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(i) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2015

/s/ JOHN P. WILKIRSON

John P. Wilkirson
Chief Financial Officer and Executive Vice President

A signed original of this written statement required by Section 906 has been provided to Cobalt International Energy, Inc. and will be retained by Cobalt International Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

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EXHIBIT 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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Exhibit 99.1

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST
J. CARTER HENSON, JR.
DAN PAUL SMITH
JOSEPH J. SPELLMAN

January 22, 2015

Mr. James H. Painter
Cobalt International Energy, Inc.
920 Memorial City Way, Suite 100
Houston, Texas 77024

Dear Mr. Painter:

In accordance with your request, we have estimated the proved undeveloped reserves and future revenue, as of December 31, 2014, to the Cobalt International Energy, Inc. (Cobalt) interest in Heidelberg Field, Green Canyon Block 859 Unit, which includes Green Canyon Blocks 859, 903, 904, and 948, located in federal waters in the Gulf of Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Cobalt and Cobalt's consolidated subsidiaries. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Cobalt's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Cobalt interest in these properties, as of December 31, 2014, to be:

	Net Reserves		Future Net Revenue (MM$)	
Category	Oil (MMBBL)	Gas (BCF)	Total	Present Worth at 10%
Proved Undeveloped	8.4	3.7	557	365

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Monetary values shown are expressed in United States dollars ($) or millions of United States dollars (MM$).

The estimates shown in this report are for proved undeveloped reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Cobalt's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Cobalt's share of capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

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1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010-3034 • PH: 713-654-4950 • FAX: 713-654-4951
nsai@nsai-petro.com
netherlandsewell.com

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil volumes, the average Light Louisiana Sweet spot price of $98.48 per barrel is adjusted for quality, transportation fees, and a market differential. For gas volumes, the average Henry Hub spot price of $4.35 per MMBTU is adjusted for energy content, transportation fees, and a market differential. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $95.24 per barrel of oil and $4.770 per MCF of gas.

Operating costs used in this report are based on estimates provided by Anadarko Petroleum Corporation (Anadarko), the operator of the properties. These costs are intended to include the per-well overhead expenses allowed under joint operating agreements along with costs to be incurred at and below the district and field levels. Since all properties are nonoperated, headquarters general and administrative overhead expenses of Cobalt are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Anadarko and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Cobalt's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Cobalt, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. These reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

The data used in our estimates were obtained from Cobalt, Anadarko, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Joseph J. Spellman, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1989 and has over 9 years of prior industry experience. Ruurdjan (Rudi) de Zoeten, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 18 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,
NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (SCOTT) REES III

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ JOSEPH J. SPELLMAN

Joseph J. Spellman, P.E. 73709
Senior Vice President

Date Signed: January 22, 2015

By: /s/ RUURDJAN (RUDI) DE ZOETEN

Ruurdjan (Rudi) de Zoeten, P.G. 3179
Vice President

Date Signed: January 22, 2015

JJS:CLM

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves—Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves—Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves*. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects—such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations—by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

QuickLinks

Exhibit 88

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Company:	MARATHON OIL CORP
Document:	10-K (FY 2014) · 03/02/2015
	Entire Document
File Number:	001-05153
Pages:	129

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2014

Commission file number 1-5153

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Street, Houston, TX 77056-2723
(Address of principal executive offices)
(713) 629-6600
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes R No £

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes £ No R

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No £

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. R

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer R Accelerated filer £ Non-accelerated filer £ Smaller reporting company £

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes £ No R

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2014: $26,831 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 674,944,619 shares of Marathon Oil Corporation Common Stock outstanding as of February 23, 2015.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2015 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to "Marathon Oil," "we," "our" or "us" in this Annual Report on Form 10-K are references to Marathon Oil Corporation, including its wholly-owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

Table of Contents

Definitions

Throughout this report, the following company or industry specific terms and abbreviations are used.

AECO - Alberta Energy Company, a Canadian natural gas benchmark price.

AMPCO - Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea in which we own a 45 percent equity interest.

AOSP - Athabasca Oil Sands Project, an oil sands mining, transportation and upgrading joint venture located in Alberta, Canada, in which we hold a 20 percent non-operated working interest.

bbl - One stock tank barrel, which is 42 United States gallons liquid volume.

bbld - Barrels per day.

bboe - Billion barrels of oil equivalent. Natural gas is converted to a barrel of oil equivalent based on the energy equivalent, which on a dry gas basis is six thousand cubic feet of gas per one barrel of oil equivalent.

bcf - Billion cubic feet.

boe - Barrels of oil equivalent.

boed - Barrels of oil equivalent per day.

btu - British thermal unit, an energy equivalence measure.

Budget - Our capital, investment and exploration spending budget as made public through a press release.

DD&A - Depreciation, depletion and amortization.

Developed acreage - The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well - A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Downstream business - The refining, marketing and transportation ("RM&T") operations, spun-off on June 30, 2011 and treated as discontinued operations.

Dry well - A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion.

E.G. - Equatorial Guinea.

EGHoldings - Equatorial Guinea LNG Holdings Limited, a liquefied natural gas production company located in E.G. in which we own a 60 percent equity interest.

EIA - United States Energy Information Agency.

EPA - United States Environmental Protection Agency.

Exploratory well - A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

FASB - Financial Accounting Standards Board.

FPSO - Floating production, storage and offloading vessel.

IFRS - International Financial Reporting Standards.

Internal Losses - Production losses attributed to factors that are within our control which can be either planned, such as a planned turnaround, or unplanned, such as equipment failure.

International E&P - Our International Exploration and Production ("Int'l E&P") segment which explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as liquefied natural gas and methanol, in E.G.

IRS - United States Internal Revenue Service.

KRG - Kurdistan Regional Government.

Light sweet crude - A crude oil with an American Petroleum Institute ("API") gravity of 38 degrees or more and a sulfur content of less than 0.5 percent.

LNG - Liquefied natural gas.

LPG - Liquefied petroleum gas.

Liquid hydrocarbons or liquids - Collectively, crude oil, synthetic crude oil, condensate and natural gas liquids.

LLS - Louisiana Light Sweet crude oil, an oil index benchmark price.

Marathon - The consolidated company prior to the June 30, 2011 spin-off of the downstream business.

Marathon Oil - Marathon Oil Corporation and its consolidated subsidiaries: the company as it exists following the June 30, 2011 spin-off of the downstream business.

Marathon Petroleum Corporation ("MPC") - The separate independent company which now owns and operates the downstream business.

mbbl - Thousand barrels.

mbbld - Thousand barrels per day.

mboe - Thousand barrels of oil equivalent.

mboed - Thousand barrels of oil equivalent per day.

mcf - Thousand cubic feet.

mmbbl - Million barrels.

mmboe - Million barrels of oil equivalent.

mmbtu - Million British thermal units.

mmcfd - Million cubic feet per day.

mmt - Million metric tonnes.

mmta - Million metric tonnes per annum.

mtd - Thousand metric tonnes per day.

Net acres or Net wells - The sum of the fractional working interests owned by us in gross acres or gross wells.

NGL or NGLs - Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, that can be collectively removed from produced natural gas, separated into these substances and sold.

North America E&P - Our North America Exploration and Production segment *("N.A. E&P")* which explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America.

OCI - Other comprehensive income.

OECD - Organization for Economic Cooperation and Development.

OPEC - Organization of Petroleum Exporting Countries.

Operational availability - A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of Internal Losses.

OSM - Our Oil Sands Mining segment which mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Productive well - A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved developed reserves - Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves - Proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves are those quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether

deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves - Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

PSC - Production sharing contract.

Quest CCS - Quest Carbon Capture and Storage project at the AOSP in Alberta, Canada.

Reserve replacement ratio - A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of liquid hydrocarbons and natural gas produced.

Royalty interest - An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SAGE - United Kingdom Scottish Area Gas Evacuation system composed of a pipeline and processing terminal.

SAR or SARs - Stock appreciation right or stock appreciation rights.

SCOOP - South Central Oklahoma Oil Province.

SEC - United States Securities and Exchange Commission.

Seismic - An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).

STACK - Sooner Trend, Anadarko (basin), Canadian (and) Kingfisher (counties).

Total depth ("TD") - The bottom of a drilled hole.

Total proved reserves - The summation of proved developed reserves and proved undeveloped reserves.

U.K. - United Kingdom.

Undeveloped acreage - Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

U.S. - United States of America.

U.S. GAAP - Accounting principles generally accepted in the U.S.

WCS - Western Canadian Select, an oil index benchmark price.

Working interest ("WI") - The interest in a mineral property which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are sometimes burdened by overriding royalty interest or other interests.

WTI - West Texas Intermediate crude oil, an oil index benchmark price.

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, including Item 1. Business, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included or incorporated by reference in this report are forward-looking statements, including without limitation statements regarding: our operational, financial and growth strategies, ability to successfully effect those strategies and the expected results therefrom; our 2015 capital, investment and exploration budget and the planned allocation thereof; planned capital expenditures and the impact thereof; planned activities, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans and maintenance activities, and the expected timing and impact thereof; expectations regarding future economic and market conditions and the effects on us thereof; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset quality and the expected benefits and performance thereof; reserve estimates and growth expectations; future production and sales expectations, and the drivers thereof; and statements related to enhanced completion designs, downspacing, co-development, high-density pilots, and the expected benefits and results thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "targets," "plans," "projects," "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including the level of supply or demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil and the impact on the price of crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- changes in political or economic conditions in key operating markets, including international markets;
- the amount of capital available for exploration and development;
- timing of commencing production from new wells;
- drilling rig availability;
- availability of materials and labor;
- the inability to obtain or delay in obtaining necessary government or third-party approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks adversely affecting our operations;
- changes in safety, health, environmental and other regulations;
- other geological, operating and economic considerations; and
- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we assume no duty to revise or update any forward-looking statements whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I

Item 1. Business

General

Marathon Oil Corporation is a global energy company based in Houston, Texas, with operations in North America, Europe and Africa. Our corporate headquarters are located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our three reportable operating segments is organized based upon both geographic location and the nature of the products and services it offers.

- North America E&P - explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P - explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining - mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

We were incorporated in 2001. On June 30, 2011, we completed the spin-off of our downstream business, creating two independent energy companies: Marathon Oil and MPC.

Strategy and Results Summary

We have production operations in the U.S., E.G., Canada, the U.K. and Libya. The focus of our U.S. operations is our three core unconventional resource plays: the Eagle Ford, Bakken and Oklahoma Resource Basins. Our exploration prospects are in E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq and the U.S, primarily in the Gulf of Mexico. Our strategy is guided by the following seven strategic imperatives ("SI^7"):

1. Living Our Values
2. Investing in Our People
3. Continuous Improvement in Operational and Capital Efficiency
4. Driving Profitable and Sustainable Growth
5. Rigorous Portfolio Management
6. Quality and Material Resource Capture
7. Delivering Long-Term Shareholder Value

In 2014, we continued to focus on liquid hydrocarbon reserves, realizing substantial increases in our three unconventional resource plays, the Eagle Ford, Bakken and Oklahoma Resource Basins. In 2014, our U.S. operations added 288 mmboe proved reserves, excluding acquisitions, dispositions and production, amounting to an increase of 37 percent over the prior year's ending balance.

For the total company, we ended 2014 with proved reserves of approximately 2,198 mmboe, compared to 2,171 mmboe at the end of 2013. Excluding proved reserves of 106 mmboe related to our Angola and Norway discontinued operations, proved reserves related to continuing operations increased from 2,065 mmboe at the end of 2013 to 2,198 mmboe at the end of 2014 for an increase of 6 percent.

We continually evaluate ways to optimize our portfolio through acquisitions and divestitures. In 2014, we executed two strategic dispositions for aggregate cash proceeds of more than $4 billion. We closed the sale of our Angola assets in the first quarter and our Norway business in the fourth quarter.

During 2014, we repurchased approximately 29 million shares for $1 billion. Our cash additions to property, plant and equipment related to continuing operations were $5.2 billion, primarily funded with cash flow from operations, with more than 70 percent of that related to our Eagle Ford, Bakken and Oklahoma Resource Basins where net sales volumes increased 35 percent year-over-year.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Outlook, for discussion of our 2015 Budget.

The map below shows the locations of our worldwide operations.

Segment and Geographic Information

For operating segment and geographic financial information, see Item 8. Financial Statements and Supplementary Data - Note 7 to the consolidated financial statements.

In the following discussion regarding our North America E&P, International E&P and Oil Sands Mining segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires.

North America E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in the U.S. and Canada.

Unconventional Resource Plays

Eagle Ford - As of December 31, 2014, we had approximately 180,000 net acres in the Eagle Ford in south Texas and 954 gross (714 net) operated producing wells, where we have been operating since 2011. During 2014, we reached total depth on 360 gross operated wells and brought 310 gross operated wells to sales, compared to 299 reaching total depth and 307 brought to sales in 2013. Included with the Eagle Ford well counts noted above, were 22 gross operated Austin Chalk wells brought online in 2014 and the first four Upper Eagle Ford wells which were brought online late in the fourth quarter of 2014. Our 2014 average spud-to-TD time was 13 days compared to 12 days in 2013. Our high-density pad drilling continues to average approximately four wells per pad in 2014. This higher pad density and the longer laterals being drilled in 2014 contribute to the slightly higher spud-to-TD time in 2014.

Throughout 2013, we evaluated the potential of downspacing to 40-acre and 60-acre spacing with several pilot programs. Wells drilled in these programs at closer spacing showed improved completion efficiency which helped offset impacts due to tighter well spacing. The continued focus on stimulation design has contributed to incremental improvements in well performance across our area of activity.

Eagle Ford net sales in 2014 were 112 mboed, 65 percent crude oil and condensate, 17 percent NGLs and 18 percent natural gas, compared to 81 mboed in 2013, a 38 percent increase. In 2014, we transported approximately 70 percent of our

Eagle Ford production by pipeline and anticipate this to increase to 90 percent in 2015 as additional pipeline capacity is constructed and completed. The ability to transport more barrels by pipeline enables us to improve/optimize price realizations, reduce costs, improve reliability and lessen our environmental footprint.

During 2014, we continued evaluation of the Austin Chalk formation across our Eagle Ford acreage position in south Texas, delineating 18,000 initial Austin Chalk acres and bringing online 22 wells. Initial Austin Chalk production results indicate that the mix of crude oil and condensate, NGLs and natural gas is similar to Eagle Ford condensate wells. We plan to drill 56 to 62 additional gross wells in the Austin Chalk formation in 2015. Co-development of the Austin Chalk and Lower Eagle Ford will leverage the infrastructure investments we have made to support production growth across the Eagle Ford operating area. During the fourth quarter of 2014, the first four Upper Eagle Ford wells were brought online and we spud our first four-well pilot with Austin Chalk, Upper Eagle Ford, and two Lower Eagle Ford wells.

We operate approximately 800 miles of gathering pipeline in the Eagle Ford area. We now have 31 central gathering and treating facilities, with aggregate capacity of more than 460 mboed. We also own and operate the Sugarloaf gathering system, a 37-mile natural gas pipeline through the heart of our acreage in Karnes, Atascosa, and Bee Counties of south Texas.

Approximately 40 percent of our 2015 Budget, $1.4 billion, is allocated to the Eagle Ford. Our drilling plans for 2015 include drilling 141 - 152 net wells (245 - 260 gross, of which we will operate 215 - 225), a decrease of approximately 40 percent over 2014. We anticipate bringing 255 - 275 gross operated wells to sales during 2015.

Bakken - We hold approximately 290,000 net acres in the Bakken shale oil play in North Dakota and eastern Montana, where we have been operating since 2006. Since inception, we have continuously sought improvement in efficiency and well performance through optimizing completion techniques. We began high-density spacing pilots in 2014, with each pad comprised of six Middle Bakken formation and six Three Forks first bench formation wells per drilling-spacing unit. We continue to execute an enhanced completion design pilot program, including elevated proppant volumes, hybrid slickwater fracs, increased stages and cemented liners, with 42 of the 55 tests online at the end of 2014.

Our time to drill a well averaged 17 days spud-to-TD in 2014 compared to 15 days in 2013. We reached TD on 83 gross operated wells and brought to sales 67 gross operated wells in 2014 compared to 76 reaching total depth and 77 brought to sales in 2013. We recompleted 35 wells during 2014.

Our net sales from the Bakken shale averaged 51 mboed in 2014, approximately 88 percent crude oil, 6 percent NGLs and 6 percent natural gas, compared to 39 mboed in 2013, a 31 percent increase. In efforts to optimize price realizations, we sell our production in local North Dakota markets and to select purchasers who may elect to transport outside the state.

Approximately 20 percent of our 2015 Budget, $760 million, is allocated to the Bakken. Our 2015 Bakken program includes plans to drill 42 - 53 net wells (100 - 120 gross, of which we will operate 38 - 48). We anticipate bringing 68 - 78 gross operated wells to sales during 2015.

Oklahoma Resource Basins - Our primary focus in 2015 will be in the SCOOP and STACK areas. In the SCOOP area we hold approximately 145,000 net acres with rights to the unconventional Woodford, Springer, Granite Wash and other Pennsylvanian sands plays. We also hold approximately 100,000 net acres in the STACK area with rights to the unconventional Woodford, Meramec and other Mississippian plays. These totals include over 50,000 acres added in the SCOOP and STACK areas in 2014. Though not a focus of the 2015 program, we also hold 57,000 net acres in the broader western Oklahoma Granite Wash and other Pennsylvanian sands plays.

In the SCOOP and STACK areas, we reached total depth on 17 gross operated wells and brought 18 gross operated wells to sales in 2014 compared to 10 reaching total depth and nine brought to sales in 2013. A total of nine net non-operated unconventional wells were brought to sales in 2014 compared to three in 2013.

Sales from our Oklahoma Resource Basins in 2014 were primarily from the Anadarko Woodford shale and averaged 18 mboed, approximately 16 percent crude oil, 28 percent NGLs and 56 percent natural gas, compared to 14 mboed in 2013, a 29 percent increase.

Approximately 6 percent of our 2015 Budget, $226 million, is allocated to the Oklahoma Resource Basins. Our drilling plans for the Oklahoma Resource Basins in 2015 include drilling and completing 17 - 20 net wells (41 - 50 gross of which 16 - 20 are company operated wells). We anticipate bringing 18 - 22 gross operated wells to sales during 2015.

See below for discussion of our conventional, primarily natural gas, production operations in Oklahoma.

Other United States

Gulf of Mexico - *Production* - On December 31, 2014, we held significant interests in 11 producing fields, four of which are company-operated. Average net sales in 2014 from the Gulf of Mexico were 14 mbbld of liquid hydrocarbons and 16 mmcfd of natural gas, or 17 mboed compared to 19 mboed in 2013. Operational availability for our operated properties was 96 percent, with internal unplanned losses of four percent.

We have a 65 percent operated working interest in the Ewing Bank Block 873 platform which is located 130 miles south of New Orleans, Louisiana. The platform serves as a production hub for the Lobster, Oyster and Arnold fields on Ewing Bank Blocks 873, 917 and 963. The facility also processes third-party production via subsea tie-backs.

We have a 50 percent non-operated working interest in the Petronius field on Viosca Knoll Blocks 786 and 830, located 130 miles southeast of New Orleans, which includes 15 producing wells. The Petronius platform is also capable of providing processing and transportation services to nearby third-party fields.

We hold a 30 percent non-operated working interest in the Neptune field located on Atwater Valley Block 575, 120 miles south off the coast of Louisiana. The development includes seven subsea wells tied back to a stand-alone platform. A new Neptune sidetrack well came online late December 2014.

We have an 18 percent non-operated working interest in the Gunflint field development located on Mississippi Canyon Blocks 948, 949, 992(N/2) and 993(N/2), 90 miles south off the coast of Louisiana. The discovery well was drilled in 2008 and encountered pay in the Middle Miocene reservoirs. Two subsequent appraisal wells were drilled and evaluated in 2012 and 2013. The subsea tie-back development project will continue to progress in 2015, with first oil expected in 2016.

Gulf of Mexico - *Exploration* - We have a 3-year shared contract on the Maersk Valiant drillship and plan to utilize the rig to test prospects in the Gulf of Mexico, including one operated exploration well in 2015. As we evaluate various opportunities for drilling, we may seek partners to further reduce our exploration risk on individual projects.

A deepwater oil discovery on the Shenandoah prospect, located on Walker Ridge Block 52, was drilled in 2009. We own a 10 percent non-operated working interest in this prospect. The first appraisal well on the Shenandoah prospect reached total depth in 2013 and was successful. The second appraisal well was spud in late May 2014 and the well costs incurred through December 31, 2014 were expensed in the fourth quarter of 2014. A third appraisal well is anticipated to spud on Walker Ridge Block 51 in 2015.

In the fourth quarter of 2014, we drilled two exploratory wells in the Gulf of Mexico: one on the Key Largo prospect, located on Walker Ridge Block 578, in which we have a 60 percent working interest and one on the Perseus prospect, located on Desoto Canyon Block, in which we have a 30 percent non-operated working interest. Neither well encountered commercial hydrocarbons and the well costs incurred through December 31, 2014 were charged to dry well expense. We have no further plans to explore either prospect.

Oklahoma - We have long-established operated and non-operated conventional production in several Oklahoma fields from which sales averaged 8 mboed in 2014 and 9 mboed in 2013.

Texas/North Louisiana/New Mexico - We hold approximately 242,000 net acres in these areas of which approximately 20,000 of the acres are in the Haynesville and Bossier natural gas shale plays. Most of the acreage in these shale plays is held by production. We participated in one gross non-operated well in the Haynesville shale play during 2014. Conventional production was primarily from the Mimms Creek, Pearwood and Haynesville fields in 2014, with net sales averaging 5 mboed in both 2014 and 2013. We also participate in several non-operated Permian Basin fields in west Texas and New Mexico. Net sales from this area averaged 7 mboed in 2014.

Wyoming - We have ongoing enhanced oil recovery waterflood projects at the mature Bighorn Basin and Wind River Basin fields and at our 100 percent owned and operated Pitchfork field. We have conventional natural gas operations in the Greater Green River Basin. Operated production at the Powder River Basin field ceased in March 2014, and plug and abandonment activities were substantially complete as of December 31, 2014.

Our Wyoming net sales averaged 16 mbbld of liquid hydrocarbons and 11 mmcfd of natural gas, or 18 mboed, during 2014 compared to 22 mboed in 2013. We drilled 11 gross operated development wells in Wyoming in 2014. In addition, we own and operate the 420-mile Red Butte Pipeline. This crude oil pipeline connects Silvertip Station on the Montana/Wyoming state line to Casper, Wyoming.

Canada

We hold interests in both operated and non-operated exploration stage oil sand leases in Alberta, Canada, which would be developed using in-situ methods of extraction. These leases cover approximately142,000 gross (54,000 net) acres in four project areas: Namur, in which we hold a 70 percent operated interest; Birchwood, in which we hold a 100 percent operated interest; Ells River, in which we hold a 20 percent non-operated interest; and Saleski in which we hold a 33 percent non-operated interest.

During 2012, we submitted a regulatory application relating to our Canada in-situ assets at Birchwood, for a proposed 12 mbbld steam assisted gravity drainage ("SAGD") demonstration project. We expect to receive regulatory approval for this project by the end of 2015. Upon receiving this approval, we will further evaluate our development plans.

North America E&P--Acquisitions

In an asset acquisition that closed August 2014, we added acreage to our Oklahoma Resource Basins at a cost of approximately $80 million before final settlement adjustments.

In the fourth quarter of 2014, we acquired additional acreage in the SCOOP, at a cost of approximately $60 million before final settlement adjustments.

International E&P Segment

We are engaged in oil and gas exploration, development and/or production activities in E.G., Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq, Libya and the U.K. We include the results of our natural gas liquefaction operations and methanol production operations in E.G. in our International E&P segment.

Africa

Equatorial Guinea - Production - We own a 63 percent operated working interest under a PSC in the Alba field which is offshore E.G. During 2014, E.G. net liquid hydrocarbon sales averaged 31 mbbld and net natural gas sales averaged 439 mmcfd, or 104 mboed, compared to 107 mboed in 2013. Operational availability from our company-operated facilities averaged approximately 98 percent in 2014, with internal unplanned losses of one percent. A compression project designed to maintain the production plateau two additional years and extend field life up to eight years is underway and is expected to be operational in 2016.

Dry natural gas from the Alba field, which remains after the condensate and LPG are removed by Alba Plant LLC, as discussed below, is supplied to AMPCO and EGHoldings under long-term contracts at fixed prices. Because of the location and limited local demand for natural gas in E.G., we consider the prices under the contracts with Alba Plant LLC, EGHoldings and AMPCO to be comparable to the price that could be realized from transactions with unrelated parties in this market under the same or similar circumstances. Any dry gas not sold is returned offshore and reinjected into the Alba field for later production.

Equatorial Guinea - Exploration - We hold a 63 percent operated working interest in the Deep Luba discovery on the Alba Block and an 80 percent operated working interest in the Corona well on Block D. We plan to develop Block D through a unitization with the Alba field, which is currently being negotiated. We also have an 80 percent operated working interest in exploratory Block A-12 offshore Bioko Island, located immediately west of our operated Alba Field. The Sodalita West #1 exploratory well was spud during 2014 and reached total depth in February 2015. This well did not encounter commercial hydrocarbons and well costs incurred through December 31, 2014 were charged to dry well expense in the fourth quarter of 2014. A second exploratory well and one Alba field infill well are expected to be drilled in 2015.

Equatorial Guinea - Gas Processing - We own a 52 percent interest in Alba Plant LLC, an equity method investee, that operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas is processed by the LPG plant. Under a long-term contract at a fixed price per btu, the LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the remaining dry natural gas in its operations. During 2014, the gross quantity of natural gas supplied to the LPG production facility was 856 mmcfd, from which 6 mbbld of secondary condensate and 19 mbbld of LPG were produced by Alba Plant LLC.

We also own 60 percent of EGHoldings and 45 percent of AMPCO, both of which are accounted for as equity method investments. EGHoldings operates an LNG production facility and AMPCO operates a methanol plant, both located on Bioko Island. These facilities allow us to monetize natural gas reserves from the Alba field.

EGHoldings' 3.7 mmta LNG production facility sells LNG under a 3.4 mmta, or 460 mmcfd, sales and purchase agreement through 2023. The purchaser under the agreement takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index. Gross sales of LNG from this production facility totaled 4 mmta in 2014. Operational availability was 98 percent in 2014, including a planned turnaround, while internal unplanned losses were less than one percent.

AMPCO had gross sales totaling 885 mt in 2014. Operational availability for this methanol plant was 90 percent in 2014, and internal unplanned losses were ten percent. Production from the plant is used to supply customers in Europe and the U.S.

Libya - We hold a 16 percent non-operated working interest in the Waha concessions, which encompass almost 13 million gross acres located in the Sirte Basin of eastern Libya. Beginning in the third quarter of 2013, our Libya operations were impacted by third-party labor strikes at the Es Sider oil terminal. In early July 2014, Libya's National Oil Corporation rescinded force majeure associated with the third-party labor strikes, and our concession term was extended for slightly more than one year. Although we had five liftings during 2014, in December 2014, Libya's National Oil Corporation once again declared force majeure at Es Sider as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. See Item 8. Financial Statements and Supplementary Data - Note 12 to the consolidated financial statements for additional information about our Libya operations.

Gabon - *Exploration* - We hold a 21.25 percent non-operated working interest in the Diaba License G4-223 and its related permit offshore Gabon, which covers approximately 2.2 million gross (477,000 net) acres. The Diaman-1B well reached total depth in the third quarter of 2013, encountering 160-180 net feet of hydrocarbon pay in the deepwater pre-salt play. Analysis confirmed dry gas accumulation with minor condensate. Multiple additional pre-salt prospects have been identified on this License. In 2014, 3D seismic acquisition was completed in the western part of the block.

In August 2014, we signed an exploration and production sharing contract for Gabon offshore Block G13, which was subsequently re-named Tchicuate. The block, which is located in the pre-salt play offshore Gabon, encompasses 277,000 acres. The seismic program is expected to be completed in the second quarter of 2015, and processing will occur through the remainder of the year. We hold a 100 percent participating interest and operatorship in the block. In the event of development, the Republic of Gabon will assume a 20 percent financed interest in the contract upon commencement of production. The State holds additional rights to participate in the block in the future as a co-investor.

Kenya - *Exploration* - We hold a 50 percent non-operated working interest in Block 9, consisting of approximately 3.9 million gross (1.9 million net) acres in northwest Kenya. The Sala-1 exploration well was spud in February 2014 on the eastern side of Block 9 and made a natural gas discovery in the second quarter of 2014. The well was drilled to a total depth of approximately 10,000 feet, and analysis indicated three zones of interest over a 3,280-foot gross interval which were subsequently drill-stem tested. The Sala-2 appraisal well spud in the third quarter of 2014, but did not encounter commercial hydrocarbons, and the well costs were charged to dry well expense. We hold a 50 percent non-operated working interest in Block 9 with the option to operate any commercial development.

We also hold a 15 percent non-operated working interest in Block 12A, covering approximately 3.8 million gross (566,000 net) acres, which is also located in northwest Kenya. The acquisition of 2D seismic on Block 12A began in 2013 and was completed in 2014. Multiple prospects have been identified and the first exploratory well is anticipated to be drilled in late 2015.

Ethiopia - *Exploration* - We hold a 20 percent non-operated working interest in the onshore South Omo Block in Ethiopia. The concession has an area of approximately 5.4 million gross (1.1 million net) acres. Two wells were drilled on the South Omo Block in 2014: the Shimela-1 well, which reached total depth in May 2014, and the Gardim-1 well, which reached total depth in July 2014. Neither well encountered commercial hydrocarbons and the well costs were charged to dry well expense during 2014.

We have a 50 percent non-operated working interest in the Rift Basin Area Block with approximately 10.5 million gross acres. We began 2D seismic acquisition in the first quarter of 2015 in order to develop prospect inventory for a future drilling program. We have the option to operate if a discovery is made.

Other - An outbreak of the Ebola virus has existed in certain regions of West Africa (Guinea, Liberia, Sierra Leone) since late 2013. Although neither E.G. nor any other African country in which we have business activities has been impacted by Ebola to date, our business operations may be adversely affected through travel or other restrictions. We continue to monitor the situation, have enhanced our emergency response plans to address any potential impact, and are working closely with appropriate external parties to maintain business continuity and the health and well-being of our staff.

Other International

United Kingdom - Net sales from the U.K. averaged 11 mbbld of liquid hydrocarbons and 28 mmcfd of natural gas, or 16 mboed, in 2014 compared to 20 mboed in 2013. Our largest asset in the U.K. sector of the North Sea is the Brae area complex where we are the operator and have a 42 percent working interest in the South, Central, North and West Brae fields and a 39 percent working interest in the East Brae field. The Brae Alpha platform and facilities host the South, Central and West Brae fields. The North Brae and East Brae fields are natural gas condensate fields which are produced via the Brae Bravo and the East Brae platforms, respectively. The East Brae platform also hosts the nearby Braemar field in which we have a 28 percent

working interest. Operational availability in 2014 for the Brae complex was 90 percent and internal unplanned losses were nine percent. We brought two South Brae infill wells online late in the second half of 2014 and plan to complete two West Brae subsea wells and one additional South Brae infill well in 2015.

The strategic location of the Brae platforms, along with pipeline and onshore infrastructure, has generated third-party processing and transportation business since 1986. Currently, the operators of 31 third-party fields are contracted to use the Brae system and 72 mboed are being processed or transported through the Brae infrastructure. In addition to generating processing and pipeline tariff revenue, this third-party business optimizes infrastructure usage.

The working interest owners of the Brae area producing assets collectively own a 50 percent non-operated interest in the SAGE system. The SAGE pipeline transports natural gas from the Brae area, and the third-party Beryl area, and has a total wet natural gas capacity of 1.1 bcf per day. The SAGE terminal at St. Fergus in northeast Scotland processes natural gas from the SAGE pipeline as well as approximately 1 bcf per day of third-party natural gas.

We own non-operated working interests in the Foinaven area complex, consisting of a 28 percent working interest in the main Foinaven field, a 47 percent working interest in East Foinaven and a 20 percent working interest in the T35 and T25 fields. The export of Foinaven liquid hydrocarbons is via shuttle tanker from an FPSO to market. All natural gas sales are to the non-operated Magnus platform for use as injection gas.

Croatia - We were awarded, as part of a consortium, seven blocks located offshore in the Adriatic Sea, subject to negotiation of a PSC with the Croatian Government. We have a 60 percent interest in the consortium.

Kurdistan Region of Iraq - In aggregate, we have approximately 109,000 net acres in the Kurdistan Region of Iraq. We have a 45 percent operated working interest in the Harir block located northeast of Erbil. For a short time in 2014, we suspended certain operations due to security concerns in the region and continue to closely monitor the situation. We also have non-operated interests in two blocks located north-northwest of Erbil: Atrush with 15 percent working interest and Sarsang with 20 percent working interest.

On the non-operated Atrush block, following the successful appraisal program and a declaration of commerciality, the Kurdistan Ministry of Natural Resources approved a plan for field development in September 2013. The development project consists of drilling three production wells and constructing a central processing facility in Phase 1 which provides for a 25-year production period. We expect first production in late 2015 with estimated initial gross production of approximately 30 mbbld of oil. Subject to further drilling and testing results, and partner and government approvals, a potential Phase 2 development could add an additional gross 30 mbbld facility. The Atrush-3 appraisal well, within the potential Phase 2 development area approximately four miles east of existing wells, confirmed the extension of the oil bearing reservoirs in 2013 and has been suspended as a potential future producer.

On the non-operated Sarsang block, the Swara Tika discovery was declared commercial in May 2014 and a field development plan was filed in June 2014. Currently, the East Swara Tika-1 exploration well is being sidetracked up-dip. Discussions are ongoing with the Ministry of Natural Resources to finalize the Swara Tika field development plan.

On the operated Harir block, we spud the Mirawa-2 appraisal well in December 2014 which is expected to reach total depth in the second quarter of 2015. In December 2014, we announced the Jisik-1 discovery and in 2013, the Mirawa-1 discovery. Both the Jisik-1 and Mirawa-1 exploratory wells had discovered multiple stacked oil and natural gas producing zones, and have been suspended for potential future use as producing wells.

Acquisitions and Dispositions

In the fourth quarter of 2014, we closed the sale of our Norway business, including the operated Alvheim FPSO, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea, with an effective date of January 1, 2014 for proceeds of approximately $2.1 billion.

In the first quarter of 2014, we closed the sales of our 10 percent non-operated working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for additional information about these dispositions, including discontinued operations presentation.

Productive and Drilling Wells

For our North America E&P and International E&P segments and discontinued operations combined, the following tables set forth gross and net productive wells and service wells as of December 31, 2014, 2013 and 2012 and drilling wells as of December 31, 2014.

	Productive Wells[a]							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2014						&sbsp;		
U.S.	7,058	2,919	2,246	1,023	2,638	760	45	25
E.G.	-	-	16	11	2	1	-	-
Other Africa	1,071	175	7	1	94	16	3	1
Total Africa	1,071	175	23	12	96	17	3	1
Other International	55	20	39	16	24	8	6	2
Total	8,184	3,114	2,308	1,051	2,758	785	54	28
2013								
U.S.	6,632	2,568	2,763	1,482	2,349	744		
E.G.	-	-	16	11	2	1		
Other Africa	1,072	175	7	1	99	16		
Total Africa	1,072	175	23	12	101	17		
Other International	77	34	40	16	28	11		
Total	7,781	2,777	2,826	1,510	2,478	772		
2012								
U.S.	6,191	2,315	3,208	1,906	2,328	736		
E.G.	-	-	14	9	4	3		
Other Africa	1,050	171	6	1	101	16		
Total Africa	1,050	171	20	10	105	19		
Other International	77	34	40	16	28	11		
Total	7,318	2,520	3,268	1,932	2,461	766		

[a] Of the gross productive wells, wells with multiple completions operated by us totaled 31, 31 and 115 as of December 31, 2014, 2013 and 2012. Information on wells with multiple completions operated by others is unavailable to us.

Drilling Activity

For our North America E&P and International E&P segments and discontinued operations combined, the following table sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed in each of the last three years.

	Development				Exploratory				
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	Total
Year Ended December 31, 2014									
U.S.	253	43	1	297	49	19	4	72	369
Africa	1	-	-	1	-	-	2	2	3
Other International	1	-	-	1	-	-	-	-	1
Total	255	43	1	299	49	19	6	74	373
Year Ended December 31, 2013									
U.S.	237	20	-	257	73	13	3	89	346
Africa	4	-	-	4	1	-	2	3	7
Other International	-	-	-	-	-	-	3	3	3
Total	241	20	-	261	74	13	8	95	356
Year Ended December 31, 2012									
U.S.	172	21	2	195	117	13	9	139	334
Africa	4	-	-	4	1	-	-	1	5
Other International	3	-	-	3	-	-	-	-	3
Total	179	21	2	202	118	13	9	140	342

Acreage

We believe we have satisfactory title to our North America E&P and International E&P properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time which may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international PSCs or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped acreage held in our North America E&P and International E&P segments combined as of December 31, 2014.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,822	1,408	1,036	865	2,858	2,273
Canada	-	-	142	54	142	54
Total North America	1,822	1,408	1,178	919	3,000	2,327
E.G.	45	29	183	164	228	193
Other Africa	12,909	2,108	26,145	9,612	39,054	11,720
Total Africa	12,954	2,137	26,328	9,776	39,282	11,913
Other International	94	33	346	110	440	143
Total	14,870	3,578	27,852	10,805	42,722	14,383

In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. If production is not established or we take no other action to extend the terms of the leases, licenses, or concessions, undeveloped acreage listed in the table below will expire over the next three years. We plan to continue the terms of many of these licenses and concession areas or retain leases through operational or administrative actions.

	Net Undeveloped Acres Expiring		
	Year Ended December 31,		
(In thousands)	2015	2016	2017
U.S.	211	150	94
E.G.	36	-	-
Other Africa	1,950	1,502	1,089
Total Africa	1,986	1,502	1,089
Other International	88	-	-
Total	2,285	1,652	1,183

Oil Sands Mining Segment

We hold a 20 percent non-operated interest in the AOSP, an oil sands mining and upgrading joint venture located in Alberta, Canada. The joint venture produces bitumen from oil sands deposits in the Athabasca region utilizing mining techniques and upgrades the bitumen to synthetic crude oils and vacuum gas oil.

The AOSP’s mining and extraction assets are located near Fort McMurray, Alberta, and include the Muskeg River and the Jackpine mines. Gross design capacity of the combined mines is 255,000 (51,000 net to our interest) barrels of bitumen per day. The AOSP operations use established processes to mine oil sands deposits from an open-pit mine, extract the bitumen and upgrade it into synthetic crude oils. Ore is mined using traditional truck and shovel mining techniques. The mined ore passes through primary crushers to reduce the ore chunks in size and is then sent to rotary breakers where the ore chunks are further reduced to smaller particles. The particles are combined with hot water to create slurry. The slurry moves through the extraction process where it separates into sand, clay and bitumen-rich froth. A solvent is added to the bitumen froth to separate out the remaining solids, water and heavy asphaltenes. The solvent washes the sand and produces clean bitumen that is required for the upgrader to run efficiently. The process yields a mixture of solvent and bitumen which is then transported from the mine to the Scotford upgrader via the approximately 300-mile Corridor Pipeline.

The AOSP's Scotford upgrader is located at Fort Saskatchewan, northeast of Edmonton, Alberta. The bitumen is upgraded at Scotford using both hydrotreating and hydroconversion processes to remove sulfur and break the heavy bitumen molecules into lighter products. Blendstocks acquired from outside sources are utilized in the production of our saleable products. The upgrader produces synthetic crude oils and vacuum gas oil. The vacuum gas oil is sold to an affiliate of the operator under a long-term contract at market-related prices, and the other products are sold in the marketplace.

As of December 31, 2014, we own or have rights to participate in developed and undeveloped leases totaling approximately 163,000 gross (33,000 net) acres. The underlying developed leases are held for the duration of the project, with royalties payable to the province of Alberta. Synthetic crude oil sales volumes for 2014 averaged 50 mbbld and net-of-royalty production was 41 mbbld.

In December 2013, a Jackpine mine expansion project received conditional approval from the Canadian government. The project includes additional mining areas, associated processing facilities and infrastructure. The government conditions relate to wildlife, the environment and aboriginal health issues. We will evaluate the potential expansion project and government conditions after infrastructure reliability initiatives are completed.

The governments of Alberta and Canada have agreed to partially fund Quest CCS for $865 million Canadian. In the third quarter of 2012, the Energy and Resources Conservation Board ("ERCB"), Alberta's primary energy regulator at that time, conditionally approved the project and the AOSP partners approved proceeding to construct and operate Quest CCS. Government funding commenced in 2012 and continued as milestones were achieved during the development, construction and operating phases. Failure of the AOSP to meet certain timing, performance and operating objectives may result in repaying some of the government funding. Construction and commissioning of Quest CCS is expected to be completed by late 2015.

Reserves

Estimated Reserve Quantities

Reserves are disclosed by continent and by country if the proved reserves related to any geographic area, on an oil equivalent barrel basis, represent 15 percent or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent, or a continent. Other International ("Other Int'l"), includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are shown as discontinued operations ("Disc Ops") for all periods presented. Approximately 76 percent of our proved reserves are located in OECD countries.

Our December 31, 2014 proved reserves were calculated using the unweighted average of closing prices for the first day of each month in 2014 within the 12-month period. The 2014 unweighted averages for certain of the benchmark prices were as follows:

- WTI crude oil - $94.99 per bbl

- Henry Hub natural gas - $4.31 per mmbtu

- Brent crude oil - $101.39 per bbl

When determining the December 31, 2014 proved reserves for each property, the benchmark prices listed above were adjusted with price differentials that account for property-specific quality and location differences. Beginning in the second half of 2014, the crude oil benchmarks began to decline and this decline continued into early 2015. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices experienced in the second half of 2014 has resulted in a reduction in the costs of developing and producing reserves. The impact of sustained reduced commodity prices on future cash flows will be partially offset by the impact of lower costs.

A sustained period of lower commodity prices could also cause us to decrease our near term capital programs and defer investment until prices improve. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

The most significant increase in total proved reserves from 2013 to 2014 related to our U.S. unconventional shale plays, while sales of reserves in place related to our Norway and Angola discontinued operations were the largest decreases in 2014 proved reserves. Excluding discontinued operations, total proved reserves related to continuing operations increased 133 mmboe primarily due to drilling programs in our U.S. unconventional shale plays and additions in E.G. and the Kurdistan Region of Iraq, offset by production. In the U.S., we added 288 mmboe in 2014, excluding purchases and sales of reserves in place and production, amounting to an increase of 37 percent over the 2013 ending balance, mainly due to downspacing, drilling activity and improved well performance. The negative 55 mmboe revision to Canadian synthetic crude oil reserves primarily reflects the impact of technical and price changes on calculated royalty volumes as well as development plan changes in the mineable areas. See Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities for more information.

The following tables set forth estimated quantities of our proved crude oil and condensate, NGL, natural gas and synthetic crude oil reserves based upon an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2014, 2013 and 2012.

	North America			Africa						
December 31, 2014	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	294	-	294	30	175	205	19	518	-	518
Natural gas liquids *(mmbbl)*	68	-	68	15	-	15	-	83	-	83
Natural gas *(bcf)*	575	-	575	664	94	758	17	1,350	-	1,350
Synthetic crude oil *(mmbbl)*	-	644	644	-	-	-	-	644	-	644
Total proved developed reserves *(mmboe)*	458	644	1,102	155	191	346	22	1,470	-	1,470
Proved Undeveloped Reserves										
Crude oil and condensate *(mmbbl)*	340	-	340	27	33	60	10	410	-	410
Natural gas liquids *(mmbbl)*	93	-	93	15	-	15	1	109	-	109
Natural gas *(bcf)*	569	-	569	541	115	656	5	1,230	-	1,230
Synthetic crude oil *(mmbbl)*	-	4	4	-	-	-	-	4	-	4
Total proved undeveloped reserves *(mmboe)*	528	4	532	133	52	185	11	728	-	728
Total Proved Reserves										
Crude oil and condensate *(mmbbl)*	634	-	634	57	208	265	29	928	-	928
Natural gas liquids *(mmbbl)*	161	-	161	30	-	30	1	192	-	192
Natural gas *(bcf)*	1,144	-	1,144	1,205	209	1,414	22	2,580	-	2,580
Synthetic crude oil *(mmbbl)*	-	648	648	-	-	-	-	648	-	648
Total proved reserves *(mmboe)*	986	648	1,634	288	243	531	33	2,198	-	2,198

	North America			Africa						
December 31, 2013	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	241	-	241	37	176	213	19	473	77	550
Natural gas liquids *(mmbbl)*	51	-	51	18	-	18	1	70	-	70
Natural gas *(bcf)*	540	-	540	823	95	918	21	1,479	20	1,499
Synthetic crude oil *(mmbbl)*	-	674	674	-	-	-	-	674	-	674
Total proved developed reserves *(mmboe)*	382	674	1,056	193	192	385	23	1,464	80	1,544
Proved Undeveloped Reserves										
Crude oil and condensate *(mmbbl)*	256	-	256	27	39	66	6	328	14	342
Natural gas liquids *(mmbbl)*	68	-	68	16	-	16	-	84	-	84
Natural gas *(bcf)*	485	-	485	497	110	607	7	1,099	73	1,172
Synthetic crude oil *(mmbbl)*	-	6	6	-	-	-	-	6	-	6
Total proved undeveloped reserves *(mmboe)*	405	6	411	125	57	182	8	601	26	627
Total Proved Reserves										
Crude oil and condensate *(mmbbl)*	497	-	497	64	215	279	25	801	91	892
Natural gas liquids *(mmbbl)*	119	-	119	34	-	34	1	154	-	154
Natural gas *(bcf)*	1,025	-	1,025	1,320	205	1,525	28	2,578	93	2,671
Synthetic crude oil *(mmbbl)*	-	680	680	-	-	-	-	680	-	680
Total proved reserves *(mmboe)*	787	680	1,467	318	249	567	31	2,065	106	2,171

	North America			Africa						
December 31, 2012	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Cont Ops	Disc Ops	Total
Proved Developed Reserves										
Crude oil and condensate *(mmbbl)*	169	-	169	45	168	213	20	402	63	465
Natural gas liquids *(mmbbl)*	29	-	29	23	-	23	1	53	-	53
Natural gas *(bcf)*	546	-	546	980	99	1,079	8	1,633	20	1,653
Synthetic crude oil *(mmbbl)*	-	653	653	-	-	-	-	653	-	653
Total proved developed reserves *(mmboe)*	289	653	942	231	185	416	22	1,380	66	1,446
Proved Undeveloped Reserves										
Crude oil and condensate *(mmbbl)*	218	-	218	27	41	68	4	290	19	309
Natural gas liquids *(mmbbl)*	59	-	59	15	-	15	-	74	-	74
Natural gas *(bcf)*	497	-	497	444	110	554	6	1,057	69	1,126
Synthetic crude oil *(mmbbl)*	-	-	-	-	-	-	-	-	-	-
Total proved undeveloped reserves *(mmboe)*	360	-	360	116	59	175	5	540	31	571
Total Proved Reserves										
Crude oil and condensate *(mmbbl)*	387	-	387	72	209	281	24	692	82	774
Natural gas liquids *(mmbbl)*	88	-	88	38	-	38	1	127	-	127
Natural gas *(bcf)*	1,043	-	1,043	1,424	209	1,633	14	2,690	89	2,779
Synthetic crude oil *(mmbbl)*	-	653	653	-	-	-	-	653	-	653
Total proved reserves *(mmboe)*	649	653	1,302	347	244	591	27	1,920	97	2,017

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Crude oil and condensate, NGL, natural gas and synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group, which includes our Director of Corporate Reserves and his staff of Reserve Coordinators. Crude oil and condensate, NGL, and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are engineers or geoscientists who hold at least a Bachelor of Science degree in the appropriate technical field, have a minimum of three years of industry experience with at least one year in reserve estimation and have completed Marathon Oil's QRE training course. Our Corporate Reserves group screens all fields with net proved reserves of 20 mmboe or greater, every year, to determine if a field review will be performed. Any change to proved reserve estimates in excess of 1 mmboe on a total field basis, within a single month, must be approved by a Reserve Coordinator.

Our Director of Corporate Reserves, who reports to our Vice President, Operations Services, has a Bachelor of Science degree in petroleum engineering and is a registered Professional Engineer in the State of Texas. In his 27 years with Marathon Oil, he has held numerous engineering and management positions, including managing our OSM segment. He is a member of the Society of Petroleum Engineers ("SPE") and a former member of the Petroleum Engineering Advisory Council for the University of Texas at Austin.

Estimates of synthetic crude oil reserves are prepared by GLJ Petroleum Consultants ("GLJ") of Calgary, Canada, third-party consultants. Their reports for all years are filed as exhibits to this Annual Report on Form 10-K. The individual responsible for the estimates of our synthetic crude oil reserves has 14 years of experience in petroleum engineering, has conducted surface mineable oil sands evaluations since 2009 and is a registered Practicing Professional Engineer in the Province of Alberta.

Audits of Estimates

Third-party consultants are engaged to provide independent estimates for fields that comprise 80 percent of our total proved reserves over a rolling four-year period for the purpose of auditing and validating our internal reserve estimates. We exceeded this percentage for the four-year period ended December 31, 2014. We have established a tolerance level of 10 percent such that initial estimates by the third-party consultants for each field are accepted if they are within 10 percent of our internal estimates. Should the third-party consultants' initial analysis fail to reach our tolerance level, both parties re-examine the information provided, request additional data and refine their analysis, if appropriate. This resolution process is continued until both estimates are within 10 percent. In the very limited instances where differences outside the 10 percent tolerance cannot be resolved by year end, a plan to resolve the difference is developed and senior management consent is obtained. The audit process did not result in any significant changes to our reserve estimates for 2014, 2013 or 2012.

During 2014, 2013 and 2012, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a certification of the prior year's reserves for the Alba field in E.G. The NSAI summary reports are filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have multiple years of industry experience, having worked for large, international oil and gas companies before joining NSAI. The senior technical advisor has over 35 years of practical experience in petroleum geosciences, with over 15 years experience in the estimation and evaluation of reserves. The second team member has over 10 years of practical experience in petroleum engineering, with 5 years experience in the estimation and evaluation of reserves. Both are registered Professional Engineers in the State of Texas.

Ryder Scott Company ("Ryder Scott") also performed audits of the prior years' reserves of several of our fields in 2014, 2013 and 2012. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 20 years of industry experience, having worked for a major international oil and gas company before joining Ryder Scott. He is a member of SPE, where he served on the Oil and Gas Reserves Committee, and is a registered Professional Engineer in the State of Texas.

Changes in Proved Undeveloped Reserves

As of December 31, 2014, 728 mmboe of proved undeveloped reserves were reported, an increase of 101 mmboe from December 31, 2013. The following table shows changes in total proved undeveloped reserves for 2014:

(mmboe)	
Beginning of year	627
Revisions of previous estimates	1
Improved recovery	1
Purchases of reserves in place	4
Extensions, discoveries, and other additions	227
Dispositions	(29)
Transfers to proved developed	(103)
End of year	728

Significant additions to proved undeveloped reserves during 2014 included 121 mmboe in the Eagle Ford and 61 mmboe in the Bakken shale plays due to development drilling. Transfers from proved undeveloped to proved developed reserves included 67 mmboe in the Eagle Ford, 26 mmboe in the Bakken and 1 mmboe in the Oklahoma Resource Basins due to development drilling and completions. Costs incurred in 2014, 2013 and 2012 relating to the development of proved undeveloped reserves, were $3,149 million, $2,536 million and $1,995 million.

A total of 102 mmboe was booked as extensions, discoveries or other additions due to the application of reliable technology. Technologies included statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, reservoir simulation and volumetric analysis. The statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved undeveloped locations establish the reasonable certainty criteria required for booking proved reserves.

Projects can remain in proved undeveloped reserves for extended periods in certain situations such as large development projects which take more than five years to complete, or the timing of when additional gas compression is needed. Of the 728 mmboe of proved undeveloped reserves at December 31, 2014, 19 percent of the volume is associated with projects that have been included in proved reserves for more than five years. The majority of this volume is related to a compression project in E.G. that was sanctioned by our Board of Directors in 2004. The timing of the installation of compression is being driven by the reservoir performance with this project intended to maintain maximum production levels. Performance of this field since the Board sanctioned the project has far exceeded expectations. Estimates of initial dry gas in place increased by roughly 10 percent between 2004 and 2010. During 2012, the compression project received the approval of the E.G. government, allowing design and planning work to progress towards implementation, with completion expected by mid-2016. The other component of Alba proved undeveloped reserves is an infill well approved in 2013 and to be drilled in the second quarter of 2015.

Proved undeveloped reserves for the North Gialo development, located in the Libyan Sahara desert, were booked for the first time in 2010. This development, which is anticipated to take more than five years to develop, is executed by the operator and encompasses a multi-year drilling program including the design, fabrication and installation of extensive liquid handling and gas recycling facilities. Anecdotal evidence from similar development projects in the region lead to an expected project execution time frame of more than five years from the time the reserves were initially booked. Interruptions associated with the civil unrest in 2011 and third-party labor strikes and civil unrest in 2013-2014 have also extended the project duration.

As of December 31, 2014, future development costs estimated to be required for the development of proved undeveloped crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves related to continuing operations for the years 2015 through 2019 are projected to be $2,915 million, $2,598 million, $2,493 million, $2,669 million and $2,745 million.

Net Production Sold

	North America			Africa					
	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
Year Ended December 31,									
2014									
Crude and condensate *(mbbld)*[a]	157	-	157	21	7	28	11	48	244
Natural gas liquids *(mbbld)*	29	-	29	10	-	10	-	-	39
Natural gas *(mmcfd)*[b]	310	-	310	439	1	440	21	37	808
Synthetic crude oil *(mbbld)*[c]	-	41	41	-	-	-	-	-	41
Total production sold *(mboed)*	238	41	279	104	7	111	15	54	459
2013									
Crude and condensate *(mbbld)*[a]	126	-	126	23	24	47	14	81	268
Natural gas liquids *(mbbld)*	23	-	23	11	-	11	1	-	35
Natural gas *(mmcfd)*[b]	312	-	312	442	22	464	25	51	852
Synthetic crude oil *(mbbld)*[c]	-	42	42	-	-	-	-	-	42
Total production sold *(mboed)*	201	42	243	107	27	134	20	89	486
2012									
Crude and condensate *(mbbld)*[a]	96	-	96	25	42	67	15	81	259
Natural gas liquids *(mbbld)*	11	-	11	11	-	11	1	-	23
Natural gas *(mmcfd)*[b][d]	358	-	358	428	15	443	33	53	887
Synthetic crude oil *(mbbld)*[c]	-	41	41	-	-	-	-	-	41
Total production sold *(mboed)*	166	41	207	108	44	152	21	90	470

[a] The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.
[b] Excludes volumes acquired from third parties for injection and subsequent resale.
[c] Upgraded bitumen excluding blendstocks.
[d] U.S. natural gas volumes exclude volumes produced in Alaska that were stored for later sale in response to seasonal demand, although our reserves had been reduced by those volumes.

Average Sales Price per Unit

	North America			Africa					
(Dollars per unit)	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
2014									
Crude and condensate *(bbl)*	$ 85.25	$ -	$ 85.25	$ 81.01	$ 94.70	$ 84.48	$ 94.31	$ 109.80	$ 90.37
Natural gas liquids *(bbl)*	33.42	-	33.42	1.00 [a]	-	1.00	67.73	-	25.25
Natural gas *(mcf)*	4.57	-	4.57	0.24 [a]	3.11	0.25	8.27	9.94	2.55
Synthetic crude oil *(bbl)*	-	83.35	83.35	-	-	-	-	-	83.35
2013									
Crude and condensate *(bbl)*	$ 94.19	$ -	$ 94.19	$ 90.62	$ 122.92	$ 107.31	$ 110.76	$ 112.36	$ 102.81
Natural gas liquids *(bbl)*	35.12	-	35.12	1.00 [a]	-	1.00	72.14	-	24.78
Natural gas *(mcf)*	3.84	-	3.84	0.24 [a]	5.44	0.49	10.64	13.01	2.75
Synthetic crude oil *(bbl)*	-	87.51	87.51	-	-	-	-	-	87.51
2012									
Crude and condensate *(bbl)*	$ 91.30	$ -	$ 91.30	$ 92.56	$ 127.31	$ 114.52	$ 109.50	$ 116.70	$ 106.35
Natural gas liquids *(bbl)*	39.57	-	39.57	1.00 [a]	-	1.00	78.81	-	23.44
Natural gas *(mcf)*	3.92	-	3.92	0.24 [a]	5.76	0.43	9.72	11.15	2.80
Synthetic crude oil *(bbl)*	-	81.72	81.72	-	-	-	-	-	81.72

[a] Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P Segment.

Average Production Cost per Unit[(a)]

	North America			Africa					
(Dollars per boe)	U.S.	Canada	Total	E.G.	Other	Total	Other Int'l	Disc Ops	Total
2014	$ 13.34	$ 46.63	$ 18.73	$ 4.03	N.M.	$ 5.72	$ 47.06	$ 8.92	$ 15.37
2013	13.60	55.42	20.79	2.88	7.40	3.80	38.87	8.24	14.51
2012	13.61	53.61	21.51	3.59	3.57	3.59	28.33	5.55	12.98

(a) Production, severance and property taxes are excluded; however, shipping and handling as well as other operating expenses are included in the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities - Results of Operations for Oil and Gas Production Activities for more information regarding production costs.

N.M. Not meaningful information due to limited sales in 2014.

Marketing and Midstream

Our operating segments include activities related to the marketing and transportation of substantially all of our liquid hydrocarbon, synthetic crude oil and natural gas production. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

As discussed previously, we currently own and operate gathering systems and other midstream assets in some of our production areas. We continue to evaluate midstream infrastructure investments in connection with our development plans.

Delivery Commitments

We have committed to deliver quantities of crude oil and synthetic crude oil to customers under a variety of contracts. As of December 31, 2014, those contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to liquid hydrocarbon production in the Eagle Ford and Bakken, and OSM synthetic crude oil production. Eagle Ford liquid hydrocarbon production sales commitments range from a minimum of 76 mbbld increasing to 113 mbbld in 2015 through 2018 and 51 mbbld to 65 mbbld in 2019 through 2020. Bakken liquid hydrocarbon production sales commitments of 10 mbbld commence in the fourth quarter of 2016 and expire June 1, 2026. Synthetic crude oil production sales commitments fall under a 3-year agreement for 13.5 mbbld which expires July 2017. Our current production rates, forecasts and proved reserves are sufficient to meet these commitments. All of these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate.

In addition to the sales contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.

Competition and Market Conditions

Strong competition exists in all sectors of the oil and gas industry and, in particular, in the exploration for and development of new reserves. We compete with major integrated and independent oil and gas companies, as well as national oil companies, for the acquisition of oil and natural gas leases and other properties. Based upon statistics compiled in the "2014 Global Upstream Performance Review" published by IHS Inc., we rank tenth among U.S.-based petroleum companies on the basis of 2013 worldwide liquid hydrocarbon and natural gas production. See Item 1A. Risk Factors for discussion of specific areas in which we compete and related risks.

We also compete with other producers of synthetic crude oil for the sale of our synthetic crude oil to refineries primarily in North America. Additional synthetic crude oil projects are being contemplated by various competitors and, if undertaken and completed, may result in a significant increase in the supply of synthetic crude oil to the market. Because not all refineries are able to process or refine synthetic crude oil in significant volumes, sufficient market demand may not exist at all times to absorb our share of the synthetic crude oil production from the AOSP at economically viable prices.

Our operating results are affected by price changes for liquid hydrocarbons and natural gas, as well as changes in competitive conditions in the markets we serve. Generally, results from oil and gas production and OSM operations benefit from higher liquid hydrocarbons and natural gas prices. Market conditions in the oil and gas industry are cyclical and subject to global economic and political events and new and changing governmental regulations. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Overview - Market Conditions for additional discussion of the impact of prices on our operations.

Environmental, Health and Safety Matters

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment, health and safety. These laws and regulations include the Occupational Safety and Health Act ("OSHA") with respect to the protection of the health and safety of employees, the Clean Air Act ("CAA") with respect to air emissions, the Federal Water Pollution Control Act (also known as the Clean Water Act ("CWA")) with respect to water discharges, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") with respect to releases and remediation of hazardous substances, the Oil Pollution Act of 1990 ("OPA-90") with respect to oil pollution and response, the National Environmental Policy Act with respect to evaluation of environmental impacts, the Endangered Species Act with respect to the protection of endangered or threatened species, the Resource Conservation and Recovery Act ("RCRA") with respect to solid and hazardous waste treatment, storage and disposal and the U.S. Emergency Planning and Community Right-to-Know Act with respect to the dissemination of information relating to certain chemical inventories. In addition, many other states and countries in which we operate have their own laws dealing with similar matters.

These laws and regulations could result in costs to remediate releases of regulated substances, including crude oil, into the environment, or costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose strict liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. New laws have been enacted and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new rules can only be broadly appraised until their implementation becomes more defined. Based on regulatory trends, particularly with respect to the CAA and its implementing regulations, we have incurred and will continue to incur capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

Air and Climate Change

The EPA proposed a more stringent National Ambient Air Quality Standard (NAAQS) for ozone in December 2014. A more stringent ozone NAAQS could result in additional areas being designated as non-attainment, including areas in which we operate, which may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with any regulation or other action by the EPA that lowers the ozone NAAQS, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented.

In August 2012, the EPA published final New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that amended existing NSPS and NESHAP standards for oil and gas facilities as well as created a new NSPS for oil and gas production, transmission and distribution facilities with a compliance deadline of January 1, 2015. While these rules remain in effect, the EPA announced in 2013 that it would reexamine and reissue the rules over the next three years. The EPA has issued updated rules regarding storage tanks and additional rules are expected. In December 2014, the EPA issued finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion of hydraulically fractured wells and clarified that storage tanks permanently removed from service are not affected by any requirements. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry, and, based on responses received, announced in early 2015 that it will begin the process of issuing a rule governing methane emissions from the oil and gas industry. If we are unable to comply with air pollution regulations or to obtain permits for emissions associated with our

operations, we could be required to forego construction, modification or certain operations. These regulations may also increase compliance costs for some facilities we own or operate, and result in administrative, civil and/or criminal penalties for non-compliance. Obtaining permits may delay the development of our oil and natural gas projects, including the construction and operation of facilities.

In 2010, the EPA promulgated rules that require us to monitor and submit an annual report on our greenhouse gas emissions. Further, state, national and international requirements to reduce greenhouse emissions are being proposed and in some cases promulgated (see discussion above regarding potential methane regulation by EPA). These requirements apply or could apply in countries in which we operate. Potential legislation and regulations pertaining to climate change could also affect our operations. The cost to comply with these laws and regulations cannot be estimated at this time. For additional information, see Item 1A. Risk Factors. As part of our commitment to environmental stewardship, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Hydraulic Fracturing

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. State and local level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. Further, the Bureau of Land Management is expected to issue a rule governing certain hydraulic fracturing practices on lands within their jurisdiction in early 2015. In addition, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process, including subjecting the process to regulation under the Safe Drinking Water Act. In the first quarter of 2010, the EPA announced its intention to conduct a comprehensive research study on the potential effects that hydraulic fracturing may have on water quality and public health. The EPA issued a progress report in late 2012, and expects to issue a draft report for public comment and peer review in 2015, with a final report expected in 2016.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs, which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

Transportation

A number of state and federal rules apply to the transportation of liquid hydrocarbons. In 2014, the U.S. Department of Transportation (“DOT”) proposed a rule relating to testing and classification of liquid hydrocarbons and imposing additional restrictions on the types of rail cars that may be used in certain types of liquid hydrocarbon service. Although our businesses do not own rail cars and purchasers of our liquid hydrocarbons make arrangements for its transportation, such regulations could increase transportation costs which are passed on to Marathon Oil by liquid hydrocarbon purchasers. We anticipate a final rule sometime in 2015. In addition, the Pipeline and Hazardous Materials Safety Administration, a sub-agency of DOT, has proposed or announced the intention to propose various rules related to pipeline transportation of natural gas and/or liquid hydrocarbons. Such regulations could increase the regulatory burden on our businesses where we own or operate pipelines, or could otherwise increase costs to third parties that are passed on to Marathon Oil.

Remediation

The AOSP operations use established processes to mine deposits of bitumen from open-pit mines, extract the bitumen and upgrade it into synthetic crude oils. Tailings are waste products created from the oil sands extraction process which are placed in ponds. The AOSP is required to reclaim its tailings ponds as part of its ongoing reclamation work. The reclamation process uses developing technology and there is an inherent risk that the current process may not be as effective or perform as required in order to meet the approved closure and reclamation plan. The AOSP continues to develop its current reclamation technology and continues to investigate alternate tailings management technologies. In February 2009, the ERCB issued a directive which more clearly defines criteria for managing oil sands tailings. We believe that we are substantially in compliance with the directive at this time. We could incur additional costs if further new regulations are issued or if we fail to comply in a timely manner.

Water

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the Clean Water Act and its various programs. If finalized as proposed, this expansion will result in additional costs of compliance as well as increased monitoring, recordkeeping, and recording for some of our facilities.

Concentrations of Credit Risk

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. For 2014, sales to Shell Oil and its affiliates accounted for approximately 10 percent of our total revenues. For 2013, sales to Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10 percent of our annual revenues. For 2012, sales to Statoil accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of our annual revenues.

Trademarks, Patents and Licenses

We currently hold a number of U.S. and foreign patents and have various pending patent applications. Although in the aggregate our trademarks, patents and licenses are important to us, we do not regard any single trademark, patent, license or group of related trademarks, patents or licenses as critical or essential to our business as a whole.

Employees

We had 3,330 active, full-time employees as of December 31, 2014. We consider labor relations with our employees to be satisfactory. We have not had any work stoppages or strikes pertaining to our employees.

Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2015, are as follows:

Lee M. Tillman	53	President and Chief Executive Officer
John R. Sult	55	Executive Vice President and Chief Financial Officer
Sylvia J. Kerrigan	49	Executive Vice President, General Counsel and Secretary
T. Mitch Little	51	Vice President, International and Offshore Production Operations
Lance W. Robertson	42	Vice President, North America Production Operations
Patrick J. Wagner	50	Vice President, Corporate Development
Gary E. Wilson	53	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed president and chief executive officer in August 2013. Mr. Tillman is also a member of our Board of Directors. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.

Mr. Sult was appointed executive vice president and chief financial officer in September 2013. Prior to joining Marathon Oil, Mr. Sult served as executive vice president and chief financial officer of El Paso Corporation (a natural gas provider) from 2010 through 2012, senior vice president and chief financial officer from 2009 to 2010, and senior vice president, chief accounting officer and controller from 2005 to 2009.

Ms. Kerrigan was appointed executive vice president, general counsel and secretary in October 2012, having served as vice president, general counsel and secretary since November 2009. Prior to these appointments, Ms. Kerrigan served as assistant general counsel since January 2003.

Mr. Little was appointed vice president, international and offshore exploration and production operations in September 2013, having served as vice president, international production operations since September 2012. Prior to that, Mr. Little was resident manager for our Norway operations and served as general manager, worldwide drilling and completions. Mr. Little joined Marathon Oil in 1986 and has since held a number of engineering and management positions of increasing responsibility.

Mr. Robertson was appointed vice president, North America production operations in September 2013, having served as vice president, Eagle Ford production operations since October 2012. Mr. Robertson joined Marathon Oil in October 2011 as regional vice president, South Texas/Eagle Ford. Between 2004 and 2011, Mr. Robertson held a number of senior engineering and operations management roles of increasing responsibility with Pioneer Natural Resources Company (an independent oil and gas company) in the U.S. and Canada.

Mr. Wagner was appointed vice president, corporate development in April 2014. Prior to joining Marathon Oil, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management (a private equity firm), which he joined in early 2012 as vice president, exploitation. Prior to that, Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director corporate accounting from February 2014 through September 2014, director global operations services finance from October 2012 through February 2014, director controls and reporting from April 2011 through September 2012, and international finance manager from September 2009 through March 2011.

Available Information

Our website is www.marathonoil.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K and other reports and filings with the SEC are available free of charge on our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. Information contained on our website is not incorporated into this Annual Report on Form 10-K or our other securities filings. Our filings are also available in hard copy, free of charge, by contacting our Investor Relations office.

The public may read and copy any materials we file with the SEC at its Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct and Code of Ethics for Senior Financial Officers;
- our Corporate Governance Principles; and
- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

A substantial, extended decline in liquid hydrocarbon or natural gas prices would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

Prices for crude oil and condensate, NGLs, natural gas and synthetic crude oil fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil and condensate, NGLs, natural gas and synthetic crude oil. Historically, the markets for crude oil and condensate, NGLs, natural gas and synthetic crude oil have been volatile and may continue to be volatile in the future. For example, beginning in the second half of 2014 and continuing into 2015, the WTI and Brent crude oil benchmarks have substantially declined. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Many of the factors influencing prices of crude oil and condensate, NGLs, natural gas and synthetic crude oil are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- the ability of the members of OPEC to agree to and maintain production controls;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornadoes;
- the price and availability of alternative and competing forms of energy;
- the effect of conservation efforts;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxes; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of crude oil and condensate, NGLs, natural gas and synthetic crude oil are uncertain. Prolonged or substantial declines in commodity prices could have adverse effects on our business, including:

- reducing the amount of crude oil and condensate, NGLs, natural gas and synthetic crude oil that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, or delay or postpone some of our capital projects, resulting in lower production of crude oil and condensate, NGLs, natural gas and synthetic crude oil;
- requiring us to impair the carrying value of our assets;
- reducing the amounts of our estimated proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves that we may produce economically;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs, natural gas and synthetic crude oil; and
- limiting our access to sources of capital, such as equity and long-term debt and/or increasing the costs of obtaining such capital.

A substantial, extended decline in liquid hydrocarbon or natural gas prices could adversely affect the abilities of our counterparties to perform their obligations to us, which could negatively impact our financial results.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, oil sands mining or liquid hydrocarbon or natural gas transportation, with partners and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. The inability of our joint venture partners to fund their portion of the costs under our joint venture agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our financial results.

Our offshore operations involve special risks that could negatively impact us.

Offshore exploration and development operations present technological challenges and operating risks because of the marine environment. Activities in deepwater areas may pose incrementally greater risks because of water depths that limit intervention capability and the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

Estimates of crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our reserves.

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering estimates. Estimates of liquid hydrocarbon and natural gas reserves were prepared by our in-house teams of reservoir engineers and geoscience professionals and were reviewed and approved by our Corporate Reserves Group. The synthetic crude oil reserves estimates were prepared by GLJ Petroleum Consultants, a third-party consulting firm experienced in working with oil sands. Reserves were valued based on the unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2014, 2013 and 2012, as well as other conditions in existence at those dates. For 2014, the average of closing prices for the first day of each month in the 12-month period were WTI crude oil of $94.99 per bbl, Henry Hub natural gas of $4.31 per mmbtu and Brent crude oil of $101.39 per bbl. Any significant future price change could have a material effect on the quantity and present value of our proved reserves. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Future reserve revisions could also result from changes in governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs, natural gas and bitumen that cannot be directly measured. (Bitumen is mined and then upgraded into synthetic crude oil.) Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other comparable producing areas;
- volumes of bitumen in-place and various factors affecting the recoverability of bitumen and its conversion into synthetic crude oil such as historical upgrader performance;
- the assumed effects of regulation by governmental agencies;
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future cash flows from our proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves reflected in this Annual Report on Form 10-K should not be considered as the market value of the reserves attributable to our properties. As required by SEC Rule 4-10 of Regulation S-X, the estimated discounted future cash flows from our proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves are based on an unweighted average of closing prices for the first day of each month in the 12-month periods ended December 31, 2014, 2013 and 2012, and costs applicable at the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor required by the applicable rules of the SEC to be used to calculate discounted future cash flows for reporting purposes is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future liquid hydrocarbon and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from liquid hydrocarbon and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance or identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves will decline materially as crude oil and condensate, NGLs, natural gas and synthetic crude oil are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs, natural gas and synthetic crude oil we produce, our future revenues will decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce crude oil and condensate, NGLs, natural gas and synthetic crude oil in promising areas;
- drilling success;
- the ability to complete long lead-time, capital-intensive projects timely and on budget;
- the ability to find or acquire additional proved reserves at acceptable costs; and
- the ability to fund such activity.

Future exploration and drilling results are uncertain and involve substantial costs.

Drilling for crude oil and condensate, NGLs and natural gas involves numerous risks, including the risk that we may not encounter commercially productive liquid hydrocarbon and natural gas reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts or surface cratering;
- lack of access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;

- increased costs or operational delays resulting from shortages of water;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our capital projects.

We may incur substantial capital expenditures and operating costs as a result of compliance with, and/or changes in environmental, health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Our businesses are subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the venting or flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions and the protection of endangered species as well as laws, regulations, and other requirements relating to public and employee safety and health and to facility security. We have incurred and may continue to incur capital, operating and maintenance, and remediation expenditures as a result of these laws, regulations, and other requirements. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results will be adversely affected. The specific impact of these laws, regulations, and other requirements may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site clean-ups or curtail operations that could materially and adversely affect our business, financial condition, results of operations and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws, regulations, and other requirements could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Our operations result in these greenhouse gas emissions. Currently, various legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in countries where we operate, including the U.S., Canada, and Norway, and the European Union. Internationally, member countries that have ratified the Kyoto Protocol have made additional commitments to reduce greenhouse gas emissions. The U.S. has not ratified the Kyoto protocol, but may do so in the future. The EPA has announced its intention to specifically regulate methane emissions from the oil and gas industry. Finalization of new legislation, regulations or international agreements in the future could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for crude oil and condensate, NGLs, natural gas and synthetic crude oil, and create delays in our obtaining air pollution permits for new or modified facilities.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Federal, state and local-level laws or regulations targeting various aspects of the hydraulic fracturing process are being considered, or have been proposed or implemented. For example, the U.S. Congress has considered legislation that would require additional regulation affecting the hydraulic fracturing process, and may be expected to do so in future legislative sessions. Further, various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In addition to such legislative and regulatory proposals, there are also a number of studies and initiatives underway that may lead to additional proposals in the future, such as the EPA research study on the potential effects that hydraulic fracturing may have on water quality and public health.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to

operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

Worldwide political and economic developments and changes in law could adversely affect our operations and materially reduce our profitability and cash flows.

Local political and economic factors in global markets could have a material adverse effect on us. A total of 41 percent of our liquid hydrocarbon and natural gas sales volumes related to continuing operations in 2014 was derived from production outside the U.S. and 55 percent of our proved crude oil and condensate, NGLs and natural gas reserves as of December 31, 2014 were located outside the U.S. All of our synthetic crude oil production and proved reserves are located in Canada. We are, therefore, subject to the political, geographic and economic risks and possible terrorist activities or other armed conflict attendant to doing business within or outside of the U.S. There are many risks associated with operations in countries such as E.G., Angola, Ethiopia, Gabon, Kenya, the Kurdistan Region of Iraq and Libya, and in global markets including:

- changes in governmental policies relating to liquid hydrocarbon or natural gas and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism, armed conflict and civil disturbances;
- the possibility that a government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens; and
- fluctuating currency values, hard currency shortages and currency controls.

For the past several years, there have been varying degrees of political instability and public protests, including demonstrations which have been marked by violence and numerous incidences of terrorist acts, within some countries in the Middle East, including Bahrain, Egypt, Iraq, Libya, Syria, Tunisia and Yemen. Some political regimes in these countries are threatened or have changed as a result of such unrest.

If such unrest continues to spread, conflicts could result in civil wars, regional conflicts, and regime changes resulting in governments that are hostile to the U.S. These may have the following results, among others:

- volatility in global crude oil prices which could negatively impact the global economy, resulting in slower economic growth rates and reduced demand for our products;
- negative impact on the world crude oil supply if transportation avenues are disrupted;
- security concerns leading to the prolonged evacuation of our personnel;
- damage to, or the inability to access, production facilities or other operating assets; and
- inability of our service and equipment providers to deliver items necessary for us to conduct our operations.

Continued hostilities in the Middle East and the occurrence or threat of future terrorist attacks, or other armed conflict, could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for crude oil and condensate, NGLs, natural gas and synthetic crude oil. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of governments through tax legislation and other changes in law, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future. Changes in law could also adversely affect our results, including new regulations resulting in higher costs to transport our production by pipeline, rail car, truck or vessel or the adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information or that could cause us to violate the non-disclosure laws of other countries.

Our commodity price risk management may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.

To the extent that we engage in price risk management activities to protect ourselves against commodity price declines, we may be prevented from fully realizing the benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Our business could be negatively impacted by cyber-attacks targeting our computer and telecommunications systems and infrastructure.

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies. Such technologies are integrated into our business operations and used as a part of our liquid hydrocarbon and natural gas production and distribution systems in the U.S. and abroad, including those systems used to transport production to market. Use of the internet and other public networks for communications, services, and storage, including "cloud" computing, exposes users (including our business) to cybersecurity risks. While our information systems and related infrastructure experienced attempted and actual minor breaches of our cybersecurity in the past, we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future. As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information systems and related infrastructure security vulnerabilities.

Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities, rail cars, trucks and vessels. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our crude oil and condensate, NGLs, natural gas and synthetic crude oil, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. Both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our crude oil could be adversely impacted by new and expected state or federal regulations relating to transportation of crude oil.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

We typically seek the acquisition of liquid hydrocarbon and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of liquid hydrocarbon and natural gas reserves (as previously discussed), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of liquid hydrocarbon and natural gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel.

Many of our major projects and operations are conducted with partners, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, or oil sands mining, with partners in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners could have a significant negative impact on our business and reputation.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our North America E&P and International E&P operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. Our OSM operations are subject to business interruptions due to breakdown or failure of equipment or processes and unplanned events such as fires, earthquakes, explosions or other interruptions. These same risks can be applied to the third-parties which transport our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage and resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, due to hurricane activity in recent years, the availability of insurance coverage for our offshore facilities for windstorms in the Gulf of Mexico region has been reduced or, in many instances, it is prohibitively expensive. As a result, our exposure to losses from future windstorm activity in the Gulf of Mexico region has increased.

Litigation by private plaintiffs or government officials could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, antitrust laws or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

In connection with our separation from MPC, MPC agreed to indemnify us for certain liabilities. However, there can be no assurance that the indemnity will be sufficient to protect us against the full amount of such liabilities, or that MPC's ability to satisfy its indemnification obligations will not be impaired in the future.

Pursuant to the Separation and Distribution Agreement and the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC agreed to indemnify us for certain liabilities. However, third parties could seek to hold us responsible for any of the liabilities that MPC agreed to retain or assume, and there can be no assurance that the indemnification from MPC will be sufficient to protect us against the full amount of such liabilities, or that MPC will be able to fully satisfy its indemnification obligations. In addition, even if we ultimately succeed in recovering from MPC any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

The spin-off could result in substantial tax liability.

We obtained a private letter ruling from the IRS substantially to the effect that the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections

355 and 368 and related provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. Rather, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also obtained an opinion of outside counsel, substantially to the effect that, the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by MPC and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

If, notwithstanding receipt of the private letter ruling and opinion of counsel, the spin-off were determined not to qualify under Section 355 of the Code, each U.S. holder of our common stock who received shares of MPC common stock in the spin-off would generally be treated as receiving a taxable distribution of property in an amount equal to the fair market value of the shares of MPC common stock received. That distribution would be taxable to each such stockholder as a dividend to the extent of our accumulated earnings and profits as of the effective date of the spin-off. For each such stockholder, any amount that exceeded those earnings and profits would be treated first as a non-taxable return of capital to the extent of such stockholder's tax basis in its shares of our common stock with any remaining amount being taxed as a capital gain. We would be subject to tax as if we had sold all the outstanding shares of MPC common stock in a taxable sale for their fair market value and would recognize taxable gain in an amount equal to the excess of the fair market value of such shares over our tax basis in such shares.

Under the terms of the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC is generally responsible for any taxes imposed on MPC or us and our subsidiaries in the event that the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment as a result of actions taken, or breaches of representations and warranties made in the Tax Sharing Agreement, by MPC or any of its affiliates. However, if the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment because of actions or failures to act by us or any of our affiliates, we would be responsible for all such taxes.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon Oil common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon Oil common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon Oil common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal liquid hydrocarbon and natural gas properties, oil sands mining properties and facilities, and other important physical properties have been described by segment under Item 1. Business.

Net crude oil and condensate, NGLs, natural gas, and synthetic crude oil sales volumes are set forth in Item 8. Financial Statements and Supplementary Data - Supplemental Statistics. Estimated net proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves are set forth in Item 8. Financial Statements and Supplementary Data - Supplementary Information on Oil and Gas Producing Activities - Estimated Quantities of Proved Oil and Gas Reserves. The basis for estimating these reserves is discussed in Item 1. Business - Reserves.

Item 3. Legal Proceedings

We are defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Environmental Proceedings

The following is a summary of proceedings involving us that were pending or contemplated as of December 31, 2014 under federal and state environmental laws. Except as described herein, it is not possible to predict accurately the ultimate outcome of these matters; however, management's belief set forth in the first paragraph under Legal Proceedings above takes such matters into account.

As of December 31, 2014, we have sites across the country where remediation is being sought under environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information, which is in many cases preliminary and incomplete, we have approximately $6 million accrued to address the clean-up and remediation costs connected with these sites.

The projected liability for clean-up and remediation provided in the preceding paragraph is a forward-looking statement. To the extent that our assumptions prove to be inaccurate, future expenditures may differ materially from those stated in the forward-looking statement.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange ("NYSE"). As of February 23, 2015, there were 39,772 registered holders of Marathon Oil common stock.

The following table reflects high and low sales prices for Marathon Oil common stock and the related dividend per share by quarter for the past two years:

	2014			2013		
(Dollars per share)	High Price	Low Price	Dividends	High Price	Low Price	Dividends
First Quarter	$35.52	$31.81	$0.19	$35.71	$31.59	$0.17
Second Quarter	$40.16	$34.90	$0.19	$36.38	$29.85	$0.17
Third Quarter	$41.69	$37.59	$0.21	$37.83	$32.61	$0.19
Fourth Quarter	$37.13	$24.80	$0.21	$37.93	$34.06	$0.19
Full Year	$41.69	$24.80	$0.80	$37.93	$29.85	$0.72

Dividends - Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on our financial condition and results of operations, although it has no obligation under Delaware law or the Restated Certificate of Incorporation to do so. In determining our dividend policy, the Board will rely on our consolidated financial statements. Dividends on Marathon Oil common stock are limited to our legally available funds.

The following table provides information about purchases by Marathon Oil and its affiliated purchaser, during the quarter ended December 31, 2014, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

	Column (a)	Column (b)	Column (c)	Column (d)
Period	Total Number of Shares Purchased[(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(c)]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(c)]
10/01/14 - 10/31/14	56,595	$36.55	-	$ 1,500,285,529
11/01/14 - 11/30/14	3,699	$35.12	-	$ 1,500,285,529
12/01/14 - 12/31/14	39,002 [(b)]	$26.70	-	$ 1,500,285,529
Total	99,296	$32.63	-	

(a) 62,242 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) 37,054 shares were repurchased in open-market transactions to satisfy the requirements for dividend reinvestment under the Marathon Oil Corporation Dividend Reinvestment and Direct Stock Purchase Plan (the "Dividend Reinvestment Plan") by the plan administrator. Shares needed to meet the requirements of the Dividend Reinvestment Plan may either be purchased in the open market or issued directly by Marathon Oil.

(c) As of December 31, 2014, we had purchased a total of 121 million common shares under the plan at a cost of $4.7 billion, which includes transaction fees and commissions that are not reported in the table above. Of this total, 29 million shares were acquired at a cost of $1 billion in the first and second quarters of 2014, 14 million shares at a cost of $500 million during the third quarter of 2013, 12 million shares at a cost of $300 million in the third quarter of 2011 and 66 million shares at a cost of $2,922 million prior to the June 30, 2011 spin-off of our downstream business. The remaining share repurchase authorization as of December 31, 2014 is $1.5 billion.

Item 6. Selected Financial Data

	Year Ended December 31,				
(In millions, except per share data)	2014[a][b]	2013[a][b]	2012[a][b]	2011[a][b]	2010 [a][b]
Statement of Income Data					
Revenues	$ 10,846	$ 11,325	$ 11,966	$ 11,088	$ 9,336
Income from continuing operations	969	931	856	467	325
Net income	3,046	1,753	1,582	2,946	2,568
Per Share Data					
Basic:					
Income from continuing operations	$1.42	$1.32	$1.21	$0.66	$0.46
Net income	$4.48	$2.49	$2.24	$4.15	$3.62
Diluted:					
Income from continuing operations	$1.42	$1.31	$1.21	$0.65	$0.46
Net income	$4.46	$2.47	$2.23	$4.13	$3.61
Statement of Cash Flows Data[b]					
Additions to property, plant and equipment related to continuing operations	$ 5,160	$ 4,443	$ 4,361	$ 2,767	$ 2,917
Dividends paid	543	508	480	567	704
Dividends per share	$0.80	$0.72	$0.68	$0.80	$0.99
Balance Sheet Data as of December 31:					
Total assets	$ 36,011	$ 35,620	$ 35,306	$ 31,371	$ 50,014
Total long-term debt, including capitalized leases	5,323	6,394	6,512	4,674	7,601

[a] Includes impairments to producing properties of $132 million, $96 million, $371 million, $310 million and $447 million in 2014, 2013, 2012, 2011 and 2010 (see Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements). Includes impairments to unproved properties of $306 million, $572 million and $227 million in 2014, 2013 and 2012 (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations).

[b] We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014 (see Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements); and our downstream business was spun-off on June 30, 2011. The applicable periods have been recast to reflect these businesses as discontinued operations.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and Item 1A. Risk Factors.

Each of our segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P - explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P - explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining - mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Executive Summary

Marathon Oil delivered against 2014 performance commitments by increasing production by 35 percent in the three core U.S. resource plays. We added 305 mmboe of net proved reserves during the year, of which 296 mmboe were in our North America E&P segment. We executed two strategic dispositions for aggregate cash proceeds of more than $4 billion, closing the sale of our Angola assets in the first quarter and our Norway business in the fourth quarter. We executed share repurchases in the first half of the year worth $1 billion. We ended 2014 with liquidity of $4.9 billion comprised of $2.4 billion of cash and $2.5 billion available through a committed multi-year credit facility. Although commodity prices began a substantial decline in the second half of 2014 which continued into 2015, we believe that we are well positioned to continue to satisfy operational objectives and capital commitments with the cash and cash equivalents on hand, internally generated cash flow from operations and available borrowing capacity.

Significant 2014 operating and financial activities include the following:

- Production from continuing operations, excluding Libya, up 8 percent over last year
- North America E&P net sales volumes averaged 238 mboed, an 18 percent increase over last year
- Production from our U.S. resource plays averaged 181 mboed, a 35 percent increase over last year
  - Eagle Ford averaged net sales volumes of 112 mboed, a 38 percent increase
  - Bakken averaged net sales volumes of 51 mboed, a 31 percent increase
  - Oklahoma Resource Basins averaged net sales volumes of 18 mboed, a 29 percent increase
- Total net proved reserves related to continuing operations increased 6 percent to approximately 2.2 bboe
- Recorded 97 percent average operational availability for our operated assets
- Announced Jisik-1 exploration discovery on the operated Harir Block in the Kurdistan Region of Iraq
- Closed Norway and Angola sales for aggregate cash proceeds of more than $4 billion
- Repurchased 29 million common shares for $1 billion
- Increased quarterly dividend by 11 percent to 21 cents per share in the second quarter
- Increased income from continuing operations per diluted share to $1.42 compared to $1.31 in 2013, by 8 percent

Market Conditions

Prevailing prices for the crude oil and condensate, NGLs, natural gas and synthetic crude oil that we produce significantly impact our revenues and cash flows. Beginning in the second half of 2014, the crude oil benchmark prices began to decline and this decline continued into early 2015. Crude oil benchmark prices are likely to remain volatile based on global supply and demand and could decline further. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Because both WTI crude oil and Brent crude oil benchmark prices were greater than $90 per barrel for the first nine months of 2014, and the Henry Hub natural gas price decline began in late 2014, the magnitude of these commodity declines is not fully evident in the tables below that report 2014 annual price realizations averages relative to our operating segments. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity - Critical Accounting Estimates for further discussion of how a substantial extended decline in commodity price changes could impact us.

North America E&P

The following table presents our average price realizations and the related benchmarks for crude oil, NGLs and natural gas for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations [(a)]			
Crude Oil and Condensate *(per bbl)*			
Bakken	$81.63	$90.25	$83.11
Eagle Ford	87.99	99.69	100.14
Oklahoma Resource Basins	87.15	94.84	89.26
Other North America [(b)]	84.21	90.42	91.75
Total Crude Oil and Condensate	85.25	94.19	91.30
Natural Gas Liquids *(per bbl)*			
Bakken	$43.25	$41.60	$42.35
Eagle Ford	29.60	30.16	32.96
Oklahoma Resource Basins	32.61	35.28	31.82
Other North America [(b)]	51.12	55.69	52.51
Total Natural Gas Liquids	33.42	35.12	39.57
Total Liquid Hydrocarbons *(per bbl)* [(c)]			
Bakken	$79.41	$87.76	$81.36
Eagle Ford	75.83	84.95	88.09
Oklahoma Resource Basins	50.86	50.77	49.21
Other North America [(b)]	81.88	88.16	89.03
Total Liquid Hydrocarbons	77.02	85.20	85.80
Natural Gas *(per mcf)*			
Bakken	$5.28	$3.90	$3.11
Eagle Ford	4.43	3.67	3.03
Oklahoma Resource Basins	4.49	3.78	3.05
Other North America [(b)]	4.65	3.95	4.20
Total Natural Gas	4.57	3.84	3.92
Benchmarks			
WTI crude oil average of daily prices *(per bbl)*	$92.91	$98.05	$94.15
LLS crude oil average of daily prices *(per bbl)*[(d)]	96.64	107.36	111.71
Mont Belvieu NGLs *(per bbl)* [(e)]	32.52	33.78	38.59
Henry Hub natural gas settlement date average (per *mmbtu)*	4.42	3.65	2.79

(a) Excludes gains or losses on derivative instruments.
(b) Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.
(c) Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per barrel by $(0.27) and $0.40 for 2013 and 2012. There were no crude oil derivative instruments for 2014.
(d) Bloomberg Finance LLP: LLS St. James.
(e) Bloomberg Finance LLP: Y-grade Mix NGL of 50% ethane, 25% propane, 10% butane, 5% isobutane and 10% natural gasoline.

Crude oil and condensate - Our crude oil and condensate price realizations may differ from the benchmark due to the quality and location of the product. Crude oil benchmark prices decreased in 2014 compared to 2013. This price decline continued into 2015 with WTI crude oil and LLS crude oil averaging $47.33 and $48.82 per bbl in January 2015.

Natural gas liquids - The majority of our NGL volumes are sold at reference to Mont Belvieu prices. Average Mount Belvieu NGL prices for 2014 were modestly lower than for 2013. Our net NGL sales volumes continue to grow due to development of our U.S. resource plays, increasing 164 percent from 2012 to 2014.

Natural gas - A significant portion of our natural gas production in the U.S. is sold at bid-week prices, or first-of-month indices relative to our specific producing areas. Average Henry Hub natural gas settlement prices were higher in 2014 compared to 2013. Henry Hub natural gas settlement prices averaged $3.19 per mmtbu for January 2015.

International E&P

The following table presents our average price realizations and the related benchmark for crude oil for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations			
Crude Oil and Condensate *(per bbl)*			
Equatorial Guinea	$81.01	$90.62	$92.56
United Kingdom	94.31	110.76	109.50
Libya	94.70	122.92	127.31
Total Crude Oil and Condensate	87.23	108.18	113.61
Natural Gas Liquids *(per bbl)*			
Equatorial Guinea[a]	$1.00	$1.00	$1.00
United Kingdom[b]	67.73	72.14	78.81
Total Natural Gas Liquids	2.46	5.24	8.32
Total Liquid Hydrocarbons *(per bbl)*			
Equatorial Guinea	$54.29	$60.34	$64.33
United Kingdom	93.75	108.92	107.31
Libya	94.70	122.92	127.31
Total Liquid Hydrocarbons	68.98	91.04	100.02
Natural Gas *(per mcf)*			
Equatorial Guinea[a]	$0.24	$0.24	$0.24
United Kingdom	8.27	10.64	9.72
Libya	3.11	5.44	5.76
Total Natural Gas	0.72	1.15	1.33
Benchmark			
Brent (Europe) crude oil *(per bbl)*[c]	$99.02	$108.64	$111.65

(a) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, Atlantic Methanol Production Company LLC and Equatorial Guinea LNG Holdings Limited, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.
(b) Related sales volumes one mbbld or less for all periods presented.
(c) Average of monthly prices obtained from EIA website.

Crude oil and condensate - Our international crude oil and condensate production is generally sold in relation to the Brent crude oil benchmark. Crude oil benchmark prices decreased in 2014 compared to 2013. This price decline continued into 2015 with Brent crude oil averaging $47.86 per bbl in January 2015.

Natural gas liquids and *natural gas* - Our NGL and natural gas sales from E.G. are subject to fixed-price, term contracts, making realized prices in this area less volatile; therefore, our reported average natural gas realized prices for the International E&P segment will not fully track market price movements. Although natural gas prices in Europe tend to be considerably higher than in the U.S., these prices decreased in 2014 compared to 2013.

Oil Sands Mining

The Oil Sands Mining segment produces and sells various qualities of synthetic crude oil. Output mix can be impacted by operational reliability or planned unit outages at the mines or upgrader. Sales prices for roughly two-thirds of the normal output mix have historically tracked movements in the WTI crude oil benchmark and one-third have historically tracked movements in the Canadian heavy crude oil benchmark, primarily WCS. Comparing 2014 and 2013, the WCS crude oil discount to WTI crude oil narrowed by $5.97 per barrel. A comparison of 2014 compared to 2013 indicate the WTI crude oil benchmark decreased while the WCS crude oil benchmark slightly increased. However, both WTI and WCS crude oil benchmarks declined in January 2015 with prices averaging $47.33 per bbl and $30.43 per bbl, respectively.

The operating cost structure of our Oil Sands Mining operations is predominantly fixed and therefore many of the costs incurred in times of full operation continue during production downtime. Per-unit costs are sensitive to production rates. Key variable costs are natural gas and diesel fuel, which track commodity markets such as the Canadian Alberta Energy Company ("AECO") natural gas sales index and crude oil prices. As average price realizations are typically at a discount to WTI and the operating cost structure for Oil Sands Mining is predominately fixed, sustained declines in oil prices could result in operating losses.

The following table presents our average price realizations and the related benchmarks that impacted both our revenues and variable costs for 2014, 2013 and 2012:

	2014	2013	2012
Average Price Realizations			
Synthetic Crude Oil *(per bbl)*	$83.35	$87.51	$81.72
Benchmark			
WTI crude oil *(per bbl)*	$92.91	$98.05	$94.15
WCS crude oil *(per bbl)*[(a)]	$73.60	$72.77	$73.18
AECO natural gas sales index *(per mmbtu)*[(b)]	$3.99	$3.08	$2.39

(a) Average of monthly prices based upon average WTI adjusted for differentials unique to western Canada.
(b) Monthly average AECO day ahead index.

Net Sales Volumes

Our net sales volumes from continuing operations averaged 415 mboed, 404 mboed and 389 mboed for 2014, 2013 and 2012. As liftings from Libya were sporadic during this 3-year period, a more representative comparison is net sales volumes from continuing operations excluding Libya, which was 408 mboed, 376 mboed and 344 mboed for 2014, 2013 and 2012. The continued ramp up of production from our U.S. resource plays has been the most significant contributor to the increases when comparing results excluding Libya, partially offset by decreases from domestic asset sales and normal production declines. Net sales volumes related to the Angola and Norway discontinued operations averaged 54 mboed, 89 mboed and 90 mboed for 2014, 2013 and 2012, representing 12 percent, 18 percent and 19 percent of total company net sales volumes in those periods.

The following table presents North America E&P segment net sales volumes by product and geographic area for 2014, 2013 and 2012:

	Year Ended December 31,		
Net Sales Volumes	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(mbbld)*			
Bakken	45	35	27
Eagle Ford	72	51	23
Oklahoma Resource Basins	3	2	1
Other North America[(a)]	37	38	45
Total Crude Oil and Condensate	157	126	96
Natural Gas Liquids *(mbbld)*			
Bakken	3	2	1
Eagle Ford	19	14	5
Oklahoma Resource Basins	5	4	2
Other North America[(a)]	2	3	3
Total Natural Gas Liquids	29	23	11
Total Liquid Hydrocarbons *(mbbld)*			
Bakken	48	37	28
Eagle Ford	91	65	28
Oklahoma Resource Basins	8	6	3
Other North America[(a)]	39	41	48
Total Liquid Hydrocarbons	186	149	107
Natural Gas *(mmcfd)*			
Bakken	18	13	8
Eagle Ford	123	94	37
Oklahoma Resource Basins	61	48	32
Other North America[(a)]	108	157	281
Total Natural Gas	310	312	358
Equivalent Barrels *(mboed)*			
Bakken	51	39	29
Eagle Ford	112	81	34
Oklahoma Resource Basins	18	14	8
Other North America[(a)]	57	67	95
Total North America E&P *(mboed)*	238	201	166

[(a)] Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.

North America E&P segment average net sales volumes in 2014 increased 18 percent when compared to 2013. Net liquid hydrocarbon sales volumes increased 37 mbbld in 2014 primarily reflecting continued growth from our three core U.S. resource plays and net natural gas sales volumes decreased 2 mmcfd in 2014 primarily due to the shut-in and exit from Powder River Basin operations and the January 2013 sale of our Alaska assets, partially offset by the increases from the U.S. resource plays.

North America E&P segment average net sales volumes in 2013 increased 21 percent when compared to 2012, primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in our three key U.S. resource plays, partially offset by lower natural gas sales volumes, primarily the result of the January 2013 sale of our Alaska assets.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

The following table presents International E&P and OSM segments net sales volumes by product and geographic area for 2014, 2013 and 2012:

	Year Ended December 31,		
Net Sales Volumes	2014	2013	2012
International E&P			
Crude Oil and Condensate *(mbbld)*			
Equatorial Guinea	21	23	25
United Kingdom	11	14	15
Libya	7	24	42
Total Crude Oil and Condensate	39	61	82
Natural Gas Liquids *(mbbld)*			
Equatorial Guinea	10	11	11
United Kingdom	-	1	1
Total Natural Gas Liquids	10	12	12
Total Liquid Hydrocarbons *(mbbld)*			
Equatorial Guinea	31	34	36
United Kingdom	11	15	16
Libya	7	24	42
Total Liquid Hydrocarbons	49	73	94
Natural Gas *(mmcfd)*			
Equatorial Guinea	439	442	428
United Kingdom[(b)]	28	32	48
Libya	1	22	15
Total Natural Gas	468	496	491
Equivalent Barrels *(mboed)*			
Equatorial Guinea	104	107	107
United Kingdom[(b)]	16	20	24
Libya	7	28	45
Total International E&P *(mboed)*	127	155	176
Oil Sands Mining			
Synthetic Crude Oil *(mbbld)*[(c)]	50	48	47
Total Continuing Operations *(mboed)*	415	404	389
Discontinued Operations - Angola *(mboed)*[(d)]	2	10	-
Discontinued Operations - Norway *(mboed)*[(d)]	52	79	90
Total Company *(mboed)*	469	493	479
Net Sales Volumes of Equity Method Investees			
LNG *(mtd)*	6,535	6,548	6,290
Methanol *(mtd)*	1,092	1,249	1,298

(b) Includes natural gas acquired for injection and subsequent resale of 6 mmcfd, 7 mmcfd and 15 mmcfd for 2014, 2013, and 2012.
(c) Includes blendstocks.
(d) As we closed the sale of our Angola assets and our Norway business during 2014, they are reflected as discontinued operations and excluded from segments in all periods presented.

International E&P segment average net sales volumes in 2014 decreased 18 percent when compared to 2013. We had lower oil sales from Libya in 2014 as a result of third party labor strikes at the Es Sider terminal and ongoing civil unrest. Excluding Libya, net sales volumes decreased 6 percent in 2014 compared to 2013, primarily due to reliability issues and production decline in the U.K. and lower reliability at the non-operated methanol facility in E.G.

International E&P segment average net sales volumes in 2013 decreased 12 percent when compared to 2012 primarily due to lower liquid hydrocarbon net sales volumes in Libya. Excluding Libya, net sales volumes only decreased 3 percent in 2013 when compared to 2012.

Refer to the Item 1. Business section for additional detail related to net sales volumes by asset.

Oil Sands Mining

Our OSM operations consist of a 20 percent non-operated working interest in the AOSP. Our net synthetic crude oil sales volumes were 50 mbbld in 2014 compared to 48 mbbld in 2013 and 47 mbbld in 2012.

Consolidated Results of Operations: 2014 compared to 2013

Consolidated income from continuing operations after income taxes in 2014 was 4 percent higher than 2013 primarily due to increased net sales volumes in the North America E&P segment which were partially offset by lower average price realizations in all segments, as well as lower net sales volumes in the International E&P segment primarily as a result of civil unrest in Libya.

Sales and other operating revenues, including related party are summarized by segment in the following table:

	Year Ended December 31,	
(In millions)	2014	2013
Sales and other operating revenues, including related party		
North America E&P	$ 5,770	$ 5,068
International E&P	1,410	2,654
Oil Sands Mining	1,556	1,576
Segment sales and other operating revenues, including related party	8,736	9,298
Unrealized loss on crude oil derivative instruments	-	(52)
Sales and other operating revenues, including related party	$ 8,736	$ 9,246

North America E&P sales and other operating revenues increased $702 million from 2013 to 2014 primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in the Eagle Ford, Bakken and Oklahoma Resource Basins, partially offset by lower average crude oil price realizations.

The following table displays changes in North America E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2013	Price Realizations	Net Sales Volumes	2014
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 4,638	$ (557)	$ 1,159	$ 5,240
Natural gas	437	82	(3)	516
Realized loss on crude oil derivative instruments	(15)	15		-
Other sales	8			14
Total	$ 5,068			$ 5,770

International E&P sales and other operating revenues decreased $1,244 million in 2014 from the prior year. This decrease was primarily due to lower liquid hydrocarbon net sales volumes in Libya as a result of civil unrest and lower average price realizations in every location.

The following table displays changes in International E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2013	Price Realizations	Net Sales Volumes	2014
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 2,398	$ (397)	$ (761)	$ 1,240
Natural gas	209	(74)	(11)	124
Other sales	47			46
Total	$ 2,654			$ 1,410

Oil Sands Mining sales and other operating revenues decreased $20 million in 2014 from 2013. This decrease was primarily due to lower average price realizations compared to 2013, partially offset by increased net sales volumes in 2014.

The following table displays changes in OSM segment sales of synthetic crude oil and other operating revenues. Refer to the preceding Market Conditions and Net Sales Volumes sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2013	Price Realizations	Net Sales Volumes	2014
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 1,542	$ (76)	$ 59	$ 1,525
Other sales	34			31
Total	$ 1,576			$ 1,556

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. These crude oil derivative instruments, all of which expired December 2013, had no impact in 2014 compared to a net unrealized loss of $52 million in 2013. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for information about our derivative positions.

Marketing revenues increased $31 million in 2014 from 2013. The increase in 2014 is primarily due to higher marketing activity levels in both the North America E&P and OSM segments. Marketing activities include the purchase of commodities from third parties for resale, or in order to meet sales contracts, and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Because the volume of marketing activity is based on market dynamics, it can fluctuate from period to period.

Net loss on disposal of assets in 2014 primarily includes the pretax loss on the sale of non-core acreage located in the far northwest portion of the Williston Basin. The net loss on disposal of assets in 2013 primarily included pretax losses on the sale of our DJ Basin interests and the conveyance of our Marcellus interests to the operator, offset by pretax gains on the sales of the Neptune gas plant and our remaining assets in Alaska. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Production expenses increased $90 million in 2014 from 2013 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken. The production expense rate (expense per boe) decreased in North America E&P in 2014 compared to 2013 primarily due to improved operating efficiencies in the Eagle Ford. The expense per boe increased in the International E&P segment due to a subsea power project at our non-operated Foinaven field as well as a turnaround in Brae in the U.K. and a non-recurring riser repair in E.G.

The following table provides production expense rates for each segment:

($ per boe)	2014	2013
North America E&P	$10.25	$10.86
International E&P	$8.31	$6.36
Oil Sands Mining [(a)]	$44.53	$46.30

[(a)] Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Other operating expenses increased $73 million in 2014 from the prior year, primarily due to increased shipping and handling costs in North America in line with increased sales volumes, as well as the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Marketing expenses increased $29 million in 2014 from the prior year, consistent with the increase in marketing revenues discussed above.

Exploration expenses decreased $98 million&332;in 2014 from 2013, primarily related to our North America E&P segment as a result of larger non-cash unproved property impairments during 2013 related to Eagle Ford leases that either expired or that we did not expect to drill. These decreases were partially offset by increases in 2014 expenses related to the operated Key Largo, the outside-operated Perseus, the outside-operated second Shenandoah appraisal well in the Gulf of Mexico and our operated Sodalita West #1 exploratory well in E.G.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	2014	2013
Unproved property impairments	$ 306	$ 572
Dry well costs	317	148
Geological and geophysical	85	80
Other	85	91
Total exploration expenses	$ 793	$ 891

Depreciation, depletion and amortization increased $361 million in 2014 from the prior year. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs. Increased DD&A expense in 2014 is primarily due to higher North America E&P sales volumes as a result of ongoing development programs over our three U.S. resource plays.

The DD&A rate, which is impacted by changes in reserves, capitalized costs and sales volume mix by field, can also cause changes to our DD&A. The following table provides DD&A rates for each segment:

($ per boe)	2014	2013
North America E&P	$26.95	$26.23
International E&P	$5.79	$5.86
Oil Sands Mining	$12.07	$12.39

Impairments in 2014 included certain Gulf of Mexico properties. Impairments in 2013 primarily related to a second LNG production train in E.G., the Ozona development in the Gulf of Mexico, and our Powder River Basin asset in Wyoming. See Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the U.S., which tend to increase or decrease in relation to sales volumes and revenues, and increased $61 million in 2014 from 2013, consistent with similar increases in the North America E&P segment.

	Year Ended December 31,	
(In millions)	2014	2013
Production and severance	$ 240	$ 202
Ad valorem	74	61
Other	92	82
Total	$ 406	$ 345

Net interest and other decreased $40 million in 2014 from 2013 primarily due to an increase in capitalized interest and higher net foreign currency gains as well as a dividend received in 2014 from a mutual insurance company of which we are an owner. See Item 8. Financial Statements and Supplementary Data - Note 8 to the consolidated financial statements for more detailed information.

Provision for income taxes decreased $1,070 million in 2014 from 2013 primarily due to the decrease in pretax income from higher tax jurisdictions, primarily Libya. The following is an analysis of the effective tax rates for 2014 and 2013.

	2014	2013
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	(6)	26
Change in permanent reinvestment assertion	(19)	-
Adjustments to valuation allowances	21	(1)
Other	(2)	1
Effective income tax rate on continuing operations	29%	61%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments appears in the "Corporate and other unallocated items" shown in the reconciliation of segment income to net income below.

Effects of foreign operations - The effects of foreign operations on our effective tax rate decreased in 2014 as compared to 2013 due to a shift in pretax income mix between high and low tax jurisdictions. This is primarily related to decreased sales in Libya where the tax rate is in excess of 90 percent. Excluding Libya, the effective tax rates on continuing operations for 2014 and 2013 would be 27 percent and 38 percent.

Change in permanent reinvestment assertion - In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S. The U.K. statutory tax rate is in excess of the U.S. statutory tax rate, and therefore, foreign tax credits associated with these earnings exceeds any incremental U.S. tax liabilities.

Adjustments to valuation allowances - In 2014, we increased the valuation allowance against foreign tax credits as a result of removing the permanent reinvestment assertion on our U.K. operations since the U.K. statutory tax rate is in excess of the U.S. statutory tax rate. In 2013, valuation allowances decreased primarily due to the disposal of our Indonesian assets.

See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for further information about income taxes.

Discontinued operations is presented net of tax. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are reflected as discontinued operations and excluded from the International E&P segment in all periods presented. Included in discontinued operations for 2014 are after-tax gains of $532 million and $976 million related to the dispositions of Angola and Norway, respectively. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements.

Average net sales volumes from Norway were 52 mboed and 79 mboed in 2014 and 2013. Sales volumes decreased in 2014 compared to 2013 primarily as the result of water breakthrough, as anticipated at Volund, as well as natural decline in the remaining fields. Alvheim sales were also impacted in 2014 by severe winter weather during the first quarter which resulted in eight days of curtailed production and again during the third quarter due to planned maintenance and system upgrades on the Alvheim FPSO. In addition, 2014 Norway sales volumes are only reported through the October 15, 2014 close date.

Segment Results: 2014 compared to 2013

Segment income for 2014 and 2013 is summarized and reconciled to net income in the following table.

	Year Ended December 31,	
(In millions)	2014	2013
North America E&P	$ 693	$ 529
International E&P	568	758
Oil Sands Mining	235	206
Segment income	1,496	1,493
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(399)	(470)
Unrealized loss on crude oil derivative instruments	-	(33)
Net loss on dispositions	(58)	(20)
Impairments	(70)	(39)
Income from continuing operations	969	931
Discontinued operations	2,077	822
Net income	$ 3,046	$ 1,753

North America E&P segment income increased $164 million in 2014 compared to 2013. The increase was largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford, Bakken and Oklahoma Resource Basins and lower exploration expenses, partially offset by lower average price realizations.

International E&P segment income decreased $190 million in 2014 compared to 2013. The decrease was primarily due to lower liquid hydrocarbon net sales volumes and lower average price realizations partially offset by a decrease in the taxes related to Libya, a high tax jurisdiction. Also, other operating expenses were higher in 2014 primarily due to the impact of a settlement related to the calculation of the net profits interest payments associated with our Alba Plant equity interests in E.G.

Oil Sands Mining segment income increased $29 million in 2014 compared to 2013. This increase was primarily a result of higher operating expenses in 2013 related to a turnaround.

Consolidated Results of Operations: 2013 compared to 2012

Consolidated income from continuing operations after income taxes in 2013 was 9 percent higher than 2012 primarily due to higher net sales volumes in the North America E&P segment, partially offset by higher exploration expenses and lower net sales volumes as well as lower average price realizations in the International E&P segment.

Sales and other operating revenues, including related party are summarized by segment in the following table:

	Year Ended December 31,	
(In millions)	2013	2012
Sales and other operating revenues, including related party		
North America E&P	$ 5,068	$ 3,944
International E&P	2,654	3,719
Oil Sands Mining	1,576	1,521
Segment sales and other operating revenues, including related party	9,298	9,184
Unrealized gain (loss) on crude oil derivative instruments	(52)	53
Sales and other operating revenues, including related party	$ 9,246	$ 9,237

North America E&P sales and other operating revenues increased $1,124 million from 2012 to 2013 primarily due to higher liquid hydrocarbon net sales volumes resulting from ongoing development programs in the Eagle Ford, Bakken and Oklahoma Resource Basins, partially offset by lower natural gas net sales volumes, primarily the result of the sale of our Alaska assets in early 2013.

The following table displays changes in North America E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2012	Price Realizations	Net Sales Volumes	2013
North America E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 3,352	$ (33)	$ 1,319	$ 4,638
Natural gas	513	(9)	(67)	437
Realized gain on crude oil				
derivative instruments	17	(17)		(15)
Other sales	62			8
Total	$ 3,944			$ 5,068

International E&P sales and other operating revenues decreased $1,065 million in 2013 from the prior year. This decrease was primarily due to lower liquid hydrocarbon net sales volumes in Libya and lower liquid hydrocarbon average price realizations.

The following table displays changes in International E&P segment sales and other operating revenues by product. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2012	Price Realizations	Net Sales Volumes	2013
International E&P Price-Volume Analysis				
Liquid hydrocarbons	$ 3,433	$ (237)	$ (798)	$ 2,398
Natural gas	240	(33)	2	209
Other sales	46			47
Total	$ 3,719			$ 2,654

Oil Sands Mining sales and other operating revenues increased $55 million in 2013 from 2012. This increase was primarily due to a higher proportion of net sales volumes related to a premium grade synthetic crude oil and the associated higher average price realizations when compared to 2012. The increase was partially offset by lower feedstock sales in 2013.

The following table displays changes in OSM segment sales of synthetic crude oil and other operating revenues. Refer to the preceding Market Conditions and Sales sections for additional detail related to average price realizations and net sales.

	Year Ended December 31,	Increase (Decrease) Related to		Year Ended December 31,
(In millions)	2012	Price Realizations	Net Sales Volumes	2013
Oil Sands Mining Price-Volume Analysis				
Synthetic crude oil	$ 1,409	$ 102	$ 31	$ 1,542
Other sales	112			34
Total	$ 1,521			$ 1,576

Unrealized gains and losses on crude oil derivative instruments are included in total sales and other operating revenues but are not allocated to the segments. These crude oil derivative instruments, all of which expired in December 2013, resulted in a $52 million net unrealized loss in 2013 compared to a net unrealized gain of $53 million in 2012. See Item 8. Financial Statements and Supplementary Data - Note 15 to the consolidated financial statements for information about our derivative positions.

Marketing revenues decreased $650 million in 2013 from 2012. North America E&P segment marketing activities, which serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points, decreased in 2013 as a result of market dynamics.

Income from equity method investments increased $53 million in 2013 from the prior year primarily due to higher LNG average price realizations.

Net gain (loss) on disposal of assets in 2013 primarily included pretax losses on the sale of our DJ Basin interests and the conveyance of our Marcellus interests to the operator offset by pretax gains on the sales of the Neptune gas plant and our remaining assets in Alaska. The net gain on disposal of assets in 2012 consisted primarily of a pretax gain on the sale of our interests in several Gulf of Mexico crude oil pipeline systems partially offset by a pretax loss related to our exit from Indonesia. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for further details about these dispositions.

Production expenses increased $77 million in 2013 from 2012 primarily related to increased North America E&P net sales volumes in the Eagle Ford and Bakken, partially offset by decreased International E&P net sales volumes. The production expense rate (expense per boe) decreased in North America E&P in 2013 compared to 2012 primarily due to improved operating efficiencies in the Eagle Ford. The production expense rate (expense per boe) increase in International E&P in 2013 compared to 2012 was primarily due to maintenance and workovers performed in Libya while production was down as a result of third-party labor strikes at the Es Sider terminal during the second half of 2013.

The following table provides production expense rates (expense per boe) for each segment:

($ per boe)	2013	2012
North America E&P	$10.86	$11.59
International E&P	$6.36	$5.85
Oil Sands Mining [(a)]	$46.30	$45.95

(a) Production expense per synthetic crude oil barrel (before royalties) includes production costs, shipping and handling, taxes other than income and insurance costs and excludes pre-development costs.

Marketing expenses decreased $658 million in 2013 from the prior year, consistent with the decreases in marketing revenues discussed above.

Exploration expenses were $206 million higher in 2013 than in 2012, primarily due to larger non-cash unproved property impairments in our North America E&P segment related to Eagle Ford leases that either expired or that we did not expect to drill, partially offset by reduced dry well costs and geological and geophysical costs. Unproved property impairments in 2012 related to Marcellus, Eagle Ford, and Indonesia.

	Year Ended December 31,	
(In millions)	2013	2012
Unproved property impairments	$ 572	$ 227
Dry well costs	148	230
Geological and geophysical	80	127
Other	91	101
Total exploration expenses	$ 891	$ 685

Depreciation, depletion and amortization increased $492 million in 2013 from the prior year. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs. Increased DD&A in 2013 primarily reflects the impact of higher North America E&P sales volumes as well as increased amortization of capitalized asset retirement costs due to revisions of estimates for abandonment obligations in the Gulf of Mexico and the U.K, partially offset by the disposition of our Alaska assets in January 2013. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about the Alaska disposition.

The DD&A rate (expense per boe), which is impacted by changes in reserves, capitalized costs and sales volume mix by field, can also cause changes to our DD&A. A higher 2013 DD&A rate in North America E&P versus 2012 is due to the ongoing development programs in the U.S. resource plays. A higher 2013 DD&A rate in International E&P versus 2012 is due to an increase in estimated abandonment costs in the U.K.

The following table provides DD&A rates for each segment:

($ per boe)	2013	2012
North America E&P	$26.23	$23.45
International E&P	$5.86	$4.96
Oil Sands Mining	$12.39	$12.57

Impairments in 2013 primarily related to capitalized costs associated with engineering and feasibility studies for a second LNG production train in E.G., the Ozona development in the Gulf of Mexico and our Powder River Basin asset in Wyoming. Impairments in 2012 were also related to the Ozona development and Powder River Basin. See Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements for information about these impairments.

Taxes other than income include production, severance and ad valorem taxes in the United States, which tend to increase or decrease in relation to sales volumes and revenues, and increased $102 million in 2013 from 2012. With the increase in North America E&P revenues and net sales volumes, production and severance taxes increased $76 million in 2013 from 2012. In addition, ad valorem taxes were slightly higher because the value of our North America E&P assets has increased with continued acquisitions in the Eagle Ford.

	Year Ended December 31,	
(In millions)	2013	2012
Production and severance	$ 202	$ 126
Ad valorem	61	57
Other	82	60
Total	$ 345	$ 243

Net interest and other increased $56 million in 2013 from 2012 primarily due to higher interest expense related to our $2 billion issuance of senior notes in late 2012. See Item 8. Financial Statements and Supplementary Data - Note 8 to the consolidated financial statements for more detailed information.

Provision for income taxes decreased $786 million in 2013 from 2012 primarily due to the decrease in pretax income from continuing operations, primarily in Libya, which is a higher tax jurisdiction. The following is an analysis of the effective income tax rates for 2013 and 2012:

	2013	2012
Statutory rate applied to income from continuing operations before income taxes	35%	35%
Effects of foreign operations, including foreign tax credits	26	36
Adjustments to valuation allowances	(1)	-
Other	1	1
Effective income tax rate on continuing operations	61%	72%

The effective income tax rate is influenced by a variety of factors including the geographic sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments appears in the "Corporate and other unallocated items" shown in the reconciliation of segment income to net income below.

Effects of foreign operations - The effects of foreign operations on our effective tax rate decreased in 2013 as compared to 2012, primarily due to decreased sales in Libya during 2013 as a result of third-party labor strikes at the Es Sider oil terminal. Excluding Libya, the effective tax rates on continuing operations for 2013 and 2012 would be 38 percent and 37 percent.

See Item 8. Financial Statements and Supplementary Data - Note 9 to the consolidated financial statements for further information about income taxes.

Discontinued operations is presented net of tax. In 2014, we closed the sales of our Angola assets and Norway business; therefore, the Angola and Norway operations are reflected as discontinued operations in all periods presented. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements.

Average net sales volumes from Norway were 79 mboed and 90 mboed in 2013 and 2012. Sales volumes decreased in 2013 compared to 2012 primarily as the result of well workovers in 2013 as well as natural decline in the remaining fields.

Segment Results: 2013 compared to 2012

Segment income for 2013 and 2012 is summarized and reconciled to net income in the following table.

	Year Ended December 31,	
(In millions)	2013	2012
North America E&P	$ 529	$ 382
International E&P	758	895
Oil Sands Mining	206	171
Segment income	1,493	1,448
Items not allocated to segments, net of income taxes:		
Corporate and other unallocated items	(470)	(467)
Unrealized gain (loss) on crude oil derivative instruments	(33)	34
Net gain (loss) on dispositions	(20)	72
Impairments	(39)	(231)
Income from continuing operations	931	856
Discontinued operations	822	726
Net income	$ 1,753	$ 1,582

North America E&P segment income increased $147 million in 2013 compared to 2012. The increase was largely due to increased liquid hydrocarbon net sales volumes primarily in the Eagle Ford, Bakken and Oklahoma Resource Basins, partially offset by higher DD&A associated with the higher sales volumes. Segment income in 2013 was also negatively impacted by the previously discussed higher exploration expenses related to non-cash unproved property impairments and the sale of our Alaska assets.

International E&P segment income decreased $137 million in 2013 compared to 2012. The decrease was primarily related to the lower liquid hydrocarbon net sales volumes in Libya and lower average liquid hydrocarbon price realizations, partially offset by lower taxes as a result of decreased pretax income from Libya which is a higher tax jurisdiction.

Oil Sands Mining segment income increased $35 million in 2013 compared to 2012. This increase was primarily due to a higher proportion of net sales volumes in 2013 related to a premium grade of synthetic crude oil with an average higher corresponding price realization.

Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Cash Flows

The following table presents sources and uses of cash and cash equivalents for 2014, 2013 and 2012:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Sources of cash and cash equivalents			
Continuing operations	$ 4,736	$ 4,388	$ 2,874
Discontinued operations	751	882	1,143
Disposals of assets	3,760	450	467
Borrowings including commercial paper, net	-	-	2,197
Other	214	189	129
Total sources of cash and cash equivalents	$ 9,461	$ 5,909	$ 6,810
Uses of cash and cash equivalents			
Acquisitions	$ (21)	$ (74)	$ (1,033)
Additions to property, plant and equipment	(5,160)	(4,443)	(4,361)
Investing activities of discontinued operations	(376)	(550)	(579)
Purchases of common stock	(1,000)	(500)	-
Commercial paper, net	(135)	(65)	-
Debt repayments	(68)	(182)	(145)
Dividends paid	(543)	(508)	(480)
Other	(24)	(7)	(21)
Total uses of cash and cash equivalents	$ (7,327)	$ (6,329)	$ (6,619)

While the 2014 commodity benchmark prices were relatively strong for most of the year, beginning in the second half of 2014 these benchmarks began to decline and continued to decline during the early portion of 2015 and remain volatile based on global supply and demand. While we are unable to predict future commodity price movements, if this lower price trend continues, it would negatively impact our cash flows from operating activities.

Cash flows from continuing operations in 2014 were higher than in 2013 due to increased net sales volumes in the North America E&P segment and lower cash tax payments (primarily Libya, a higher tax jurisdiction), partially offset by lower average price realizations in all segments, as well as lower net sales volumes in the International E&P segment. The increase in cash flows from continuing operations in 2013 primarily reflects the increase in North America E&P liquid hydrocarbon net sales volumes on operating income.

Disposals of assets in 2014 primarily reflect the $2 billion aggregate proceeds from the sale of our Angola assets in the first quarter and $2.1 billion proceeds from the sale of our Norway business in the fourth quarter. In 2013, net proceeds were primarily related to the sales of our interests in Alaska, the Neptune gas plant and the DJ Basin. In 2012, net proceeds were primarily from the sales of our interests in several Gulf of Mexico crude oil pipeline systems, a sell-down of our interests in the Harir and Safen blocks in the Kurdistan Region of Iraq and the final collection of proceeds on a 2009 asset sale. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements.

Additions to property, plant and equipment are our most significant use of cash and cash equivalents. The following table shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows for 2014, 2013 and 2012:

	Year Ended December 31,		
(In millions)	2014	2013	2012
North America E&P	$ 4,698	$ 3,649	$ 3,988
International E&P	534	456	235
Oil Sands Mining	212	286	188
Corporate	51	58	115
Total capital expenditures	5,495	4,449	4,526
Change in capital expenditure accrual	(335)	(6)	(165)
Additions to property, plant and equipment	$ 5,160	$ 4,443	$ 4,361

As of December 31, 2014, we had repurchased a total of 121 million common shares at a cost of $4.7 billion, including 29 million shares at a cost of $1 billion in the first six months of 2014 and 14 million shares at a cost of $500 million in the third quarter of 2013.

See Item 8. Financial Statements and Supplementary Data - Note 22 to the consolidated financial statements for discussion of purchases of common stock.

Liquidity and Capital Resources

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, continued access to capital markets, our committed revolving credit facility and sales of non-strategic assets. Our working capital requirements are supported by these sources and we may issue commercial paper backed by our $2.5 billion revolving credit facility to meet short-term cash requirements. Because of the alternatives available to us as discussed above and access to capital markets through the shelf registration discussed below, we believe that our short-term and long-term liquidity is adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities and other amounts that may ultimately be paid in connection with contingencies.

At December 31, 2014, we had approximately $4.9 billion of liquidity consisting of $2.4 billion in cash and cash equivalents and $2.5 billion availability under our revolving credit facility. As discussed in more detail below in “Outlook”, we are targeting a $3.5 billion Budget for 2015. Based on our projected 2015 cash outlays for our capital program and dividends, we expect to outspend our cash flows from operations for the year. We will be constantly monitoring our available liquidity during 2015 and we have the flexibility to adjust our Budget throughout the year in response to the commodity price environment. We will also continue to drive the fundamentals of expense management, including organizational capacity and operational reliability.

Capital Resources

Credit Arrangements and Borrowings

In May 2014, we amended our $2.5 billion unsecured revolving credit facility and extended the maturity to May 2019. See Note 16 to the consolidated financial statements for additional terms and rates. At December 31, 2014, we had no borrowings against our revolving credit facility and no amounts outstanding under our U.S. commercial paper program that is backed by the revolving credit facility.

At December 31, 2014, we had $6,391 million in long-term debt outstanding, and $1,068 million is due within one year, of which the majority is due in the fourth quarter of 2015. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

Shelf Registration

We have a universal shelf registration statement filed with the SEC, under which we, as "well-known seasoned issuer" for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities from time to time.

Cash-Adjusted Debt-To-Capital Ratio

Our cash-adjusted debt-to-capital ratio (total debt-minus-cash to total debt-plus-equity-minus-cash) was 16 percent at December 31, 2014 and 25 percent at December 31, 2013.

(Dollars in millions)	2014	2013
Commercial paper	$ -	$ 135
Long-term debt due within one year	1,068	68
Long-term debt	5,323	6,394
Total debt	$ 6,391	$ 6,597
Cash	$ 2,398	$ 264
Equity	$ 21,020	$ 19,344
Calculation		
Total debt	$ 6,391	$ 6,597
Minus cash	2,398	264
Total debt minus cash	3,993	6,333
Total debt	6,391	6,597
Plus equity	21,020	19,344
Minus cash	2,398	264
Total debt plus equity minus cash	$ 25,013	$ 25,677
Cash-adjusted debt-to-capital ratio	16%	25%

Capital Requirements

Capital Spending

Our approved Budget for 2015 is $3.5 billion. Additional details are discussed below in "Outlook."

Share Repurchase Program

The remaining share repurchase authorization as of December 31, 2014 is $1.5 billion.

Other Expected Cash Outflows

As of December 31, 2014, $1,068 million of our long-term debt is due in the next twelve months, most of which is due in the fourth quarter of 2015. Dividends of $543 million were paid during 2014 reflecting quarterly dividends of $0.19 per share in the first two quarters of the year and $0.21 per share in the last two quarters. On January 28, 2015, we announced that our Board of Directors had declared a dividend of $0.21 cents per share on Marathon Oil common stock, payable March 10, 2015, to stockholders of record at the close of business on February 18, 2015.

We plan to make contributions of up to $95 million to our funded pension plans during 2015. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $11 million and $19 million in 2015.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2014.

(In millions)	Total	2015	2016-2017	2018-2019	Later Years
Short and long-term debt (includes interest)[a]	$ 10,102	$ 1,363	$ 1,272	$ 1,508	$ 5,959
Lease obligations	200	41	61	50	48
Purchase obligations:					
Oil and gas activities[b]	783	442	218	74	49
Service and materials contracts[c]	1,077	166	199	89	623
Transportation and related contracts	1,933	222	475	434	802
Drilling rigs and fracturing crews[d]	629	422	207	-	-
Other	192	50	29	30	83
Total purchase obligations	4,614	1,302	1,128	627	1,557
Other long-term liabilities reported in the consolidated balance sheet[e]	943	133	156	214	440
Total contractual cash obligations[f]	$ 15,859	$ 2,839	$ 2,617	$ 2,399	$ 8,004

[a] Includes anticipated cash payments for interest of $295 million for 2015, $590 million for 2016-2017, $426 million for 2018-2019 and $2,422 million for the remaining years for a total of $3,733 million.

[b] Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

[c] Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

[d] Some contracts may be canceled at an amount less than the contract amount. Were we to elect that option where possible at December 31, 2014 our minimum commitment would be $459 million.

[e] Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2024. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

[f] This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,958 million. See Item 8. Financial Statements and Supplementary Data - Note 17 to the consolidated financial statements.

Transactions with Related Parties

We own a 63 percent working interest in the Alba field offshore E.G. Onshore E.G., we own a 52 percent interest in an LPG processing plant, a 60 percent interest in an LNG production facility and a 45 percent interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We will issue stand alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2014, 2013 and 2012 aggregated $101 million, $119 million, and $139 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to insure our payments for outstanding company debt and future abandonment liabilities.

Outlook

Budget

Our Board of Directors approved a Budget of $3.5 billion for 2015, including capital expenditures of $3.4 billion. With the continued uncertainty in commodity pricing, we have taken decisive action to protect our optionality and position us to be a stronger E&P company in the long term. Our exploration spending has been reduced by more than 50 percent while we continue to focus on our three U.S. resource plays. We are also prepared to exercise further flexibility in our spend levels as pricing and the macro environment warrant. Our Budget is broken down by reportable segment in the table below.

(In millions)		2015 Budget	Percent of Total
North America E&P	$	2,885	82%
International E&P		536	15%
Oil Sands Mining [(a)]		21	1%
Segment total		3,442	98%
Corporate and other		79	2%
Total capital, investment and exploration spending budget	$	3,521	100%

(a) Represents the net budget after factoring in reimbursements from the Canadian Federal and Provincial government related to the QUEST CCS project.

North America E&P - Approximately $2.4 billion of our Budget is allocated to our three core U.S. resource plays. More than $1.4 billion is earmarked for the Eagle Ford, where rig count is expected to drop from 18 in late 2014 to 10 by the end of the second quarter of 2015. Included in Eagle Ford spending is approximately $1 billion for drilling and completions. We plan to spend $760 million in the Bakken in North Dakota. Drilling activity will be reduced to two rigs by the end of the first quarter of 2015, down from seven rigs at the end of 2014. Bakken spending includes approximately $550 million for drilling, completions and recompletions. Spending of $226 million is targeted for the Oklahoma Resource Basins, which will also be down to two rigs by the end of the first quarter of 2015. This includes spending of approximately $200 million for drilling and completions.

International E&P - We plan to spend approximately $429 million on our international assets, primarily in E.G., the U.K. and the Kurdistan Region of Iraq.

Approximately $232 million will be spent on a targeted exploration program impacting both the North America E&P and the International E&P segments. The program includes one operated Gulf of Mexico well, participation in a non-operated appraisal well at Shenandoah in the Gulf of Mexico and seismic surveys in Gabon and Ethiopia.

Oil Sands Mining - We expect to spend $95 million for sustaining capital projects in the OSM segment. We hold a 20 percent outside-operated interest in the Athabasca Oil Sands Project.

The remainder of our Budget consists of Corporate and Other and is expected to total approximately $79 million, of which $40 million represents capitalized interest on assets under construction.

For information about expected exploration and development activities more specific to individual assets, see Item 1. Business.

Production Volumes

We forecast 2015 production available for sale from the combined North America E&P and International E&P segments, excluding Libya, to be 370 to 390 net mboed and the OSM segment to be 35 to 45 net mbbld of synthetic crude oil. We expect our U.S. resource plays to achieve production growth of approximately 20 percent in 2015 over 2014. In addition, we expect total production growth, excluding Libya, of 5 to 7 percent year-over-year.

Acquisitions and Dispositions

Excluded from our Budget are the impacts of acquisitions and dispositions not previously announced. We continually evaluate ways to optimize our portfolio through acquisitions and divestitures. In connection with our ongoing portfolio management, future decisions to dispose of assets could result in non-cash impairments in the period such decisions are made.

Personnel

In February 2015, we announced a reduction in workforce impacting approximately 350-400 employees. These reductions focus largely on U.S. payroll employees, weighted toward above-the-field and support services personnel, though we will continue to analyze our staffing needs at all levels and in all locations. Affected employees will be eligible for severance benefits.

Other

Two exploratory wells: Key Largo in the Gulf of Mexico and Sodalita West #1 in E.G. were deemed unsuccessful in early 2015, with well costs incurred through December 31, 2014 charged to dry well expense. In addition, approximately $45 million in costs related to these wells will be charged to dry well expense in the first quarter of 2015.

Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and may continue to incur substantial capital, operating and maintenance and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes.

Legislation and regulations pertaining to climate change and greenhouse gas emissions have the potential to materially adversely impact our business, financial condition, results of operations and cash flows, including costs of compliance and permitting delays. The extent and magnitude of these adverse impacts cannot be reliably or accurately estimated at this time because specific regulatory and legislative requirements have not been finalized and uncertainty exists with respect to the measures being considered, the costs and the time frames for compliance, and our ability to pass compliance costs on to our customers. For additional information see Item 1A. Risk Factors.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future. We strive to comply with all legal requirements regarding the environment, but as not all costs are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

For more information on environmental regulations that impact us, or could impact us, see Item 1. Business - Environmental, Health and Safety Matters, Item 1A. Risk Factors and Item 3. Legal Proceedings.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

The estimation of quantities of net reserves is a highly technical process performed by our engineers for crude oil and condensate, NGLs and natural gas and by outside consultants for synthetic crude oil, which is based upon several underlying assumptions that are subject to change. Estimates of reserves may change, either positively or negatively, as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Reserve estimates are based upon an unweighted average of commodity prices in the prior 12-month period, using the closing prices on the first day of each month. Sustained reduced commodity prices could have a material effect on the quantity and present value of our proved reserves and could also cause us to decrease our near term capital programs and defer investment until prices improved. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business.

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil and condensate, NGLs, natural gas and synthetic crude oil reserves.

The existence and the estimated amount of reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. Additionally, both the expected future cash flows to be generated by oil and gas producing properties used in testing such properties for impairment and the expected future taxable income available to realize deferred tax assets also rely, in part, on estimates of quantities of net reserves.

Depreciation and depletion of crude oil and condensate, NGLs, natural gas and synthetic crude oil producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. Over the past three years, the impact on our depreciation and depletion rate due to revisions of previous reserve estimates has not been significant to any of our segments. However, because we depreciate a majority of our oil and gas properties under the units-of-production method, any reduction in proved reserves could result in an acceleration of future DD&A expense. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical five percent change in 2014 proved reserves based on 2014 production.

	Impact of a Five Percent Increase in Proved Reserves		Impact of a Five Percent Decrease in Proved Reserves	
(In millions, except per boe)	DD&A per boe	Pretax Income	DD&A per boe	Pretax Income
North America E&P	$ (1.28)	$ 112	$ 1.42	$ (123)
International E&P	$ (0.28)	$ 13	$ 0.30	$ (14)
Oil Sands Mining	$ (0.63)	$ 9	$ 0.55	$ (8)

Asset Retirement Obligations

We have material legal, regulatory and contractual obligations to remove and dismantle long-lived assets and to restore land or seabed at the end of oil and gas production operations, including bitumen mining operations. A liability equal to the fair value of such obligations and a corresponding capitalized asset retirement cost are recognized on the balance sheet in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be made. The capitalized asset retirement cost is depreciated using the units-of-production method and the discounted liability is accreted over the period until the obligation is satisfied, the impacts of which are recognized as DD&A in the consolidated statements of income. In many cases, the satisfaction and subsequent discharge of these liabilities is projected to occur many years, or even decades, into the future. Furthermore, the legal, regulatory and contractual requirements often do not provide specific guidance regarding removal practices and the criteria that must be fulfilled when the removal and/or restoration event actually occurs.

Estimates of retirement costs are developed for each property based on numerous factors, such as the scope of the dismantlement, timing of settlement, interpretation of legal, regulatory and contractual requirements, type of production and processing structures, depth of water (if applicable), reservoir characteristics, depth of the reservoir, market demand for equipment, currently available dismantlement and restoration procedures and consultations with construction and engineering professionals. Inflation rates and credit-adjusted-risk-free interest rates are then applied to estimate the fair values of the obligations. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Changes in estimated asset retirement obligations for late life assets could result in future impairment charges. See Item 8. Financial Statements and Supplementary Data - Note 17 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management’s best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill;
- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed; and
- recorded value of derivative instruments.

Impairment Assessments of Long-Lived Assets and Goodwill

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of crude oil and condensate, NGLs, natural gas or synthetic crude oil, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

Long-lived assets in use are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of an impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field for our North America E&P and International E&P assets and at the project level for OSM assets. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. The substantial decline in commodity prices during the second half of 2014, and the resulting change in future commodity price assumptions, was a triggering event which required us to reassess long-lived assets related to oil and gas producing properties for impairment as of December 31, 2014. We estimated the fair values using an income approach and concluded that no material impairments were required. See Item 8. Financial Statements and Supplementary Data Note 14 to the consolidated financial statements for discussion of impairments recorded in 2014, 2013 and 2012. Future impairments of long-lived assets are possible if management’s current assumptions were to change.

Unlike long-lived assets, goodwill must be tested for impairment at least annually, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying

amount. Goodwill is tested for impairment at the reporting unit level. After we performed our annual impairment test in April 2014, there was a substantial decline in commodity prices as discussed above. The resulting change in future commodity price assumptions, was a triggering event which required us to reassess our goodwill for impairment as of December 31, 2014. Based on the results of this assessment, we concluded no impairment was required. The calculated fair value of the North America E&P and International E&P reporting units exceeded their respective book values by a significant margin.

Fair value calculated for the purpose of testing our long-lived assets and goodwill for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- **Future crude oil and condensate, NGLs, natural gas and synthetic crude oil prices.** Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates, and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in crude oil and condensate, NGLs, natural gas and synthetic crude oil prices and estimates of such future prices are inherently imprecise.
- **Estimated quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil.** Such quantities are based on a combination of proved and probable reserves such that the combined volumes represent the most likely expectation of recovery.
- **Expected timing of production.** Production forecasts are the outcome of engineer studies which estimate reserves, as well as expected capital development programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.
- **Discount rate commensurate with the risks involved.** We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.
- **Future capital requirements.** Our estimates of future capital requirements are based upon a combination of authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections. A further sustained decline in commodity prices may cause us to reassess our long-lived assets and goodwill for impairment, and could result in future non-cash impairment charges as a result of such impairment assessments.

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g. reserves, pricing and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Acquisitions

In accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values of property, plant and equipment and identifiable intangible assets. The most significant assumptions relate to the estimated fair values allocated to proved and unproved liquid hydrocarbon, natural gas and synthetic crude oil properties. Estimated fair values assigned to assets acquired can have a significant effect on our results of operations in the future. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance. During 2014, 2013 and 2012, we completed several business combinations in the Eagle Ford, the purchase prices of which were allocated to the assets acquired and liabilities assumed based on their estimated fair values (see Item 8. Financial Statements and Supplementary Data - Note 4 to the consolidated financial statements).

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to estimate reserves as described above under Estimated Quantities of Net Reserves, project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in

determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Derivatives

We record all derivative instruments at fair value. Fair value measurements for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are discussed in Item 8. Financial Statements and Supplementary Data - Note 14 to the consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Income Taxes

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

We have recorded deferred tax assets and liabilities for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. We must consider any prudent and feasible tax planning strategies that might minimize the amount of deferred tax liabilities recognized or the amount of any valuation allowance recognized against deferred tax assets, if we can implement the strategies and we expect to implement them in the event the forecasted conditions actually occur. Assumptions related to the permanent reinvestment of the earnings of our foreign subsidiaries are reconsidered quarterly to give effect to changes in our portfolio of producing properties and in our tax profile. In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S.

Our net deferred tax assets, after valuation allowances, are expected to be realized through our future taxable income and the reversal of temporary differences. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices) and the assessment of the effects of foreign taxes on our U.S. federal income taxes. The estimates and assumptions used in determining future taxable income are consistent with those used in our planning and capital investment reviews. We consider a combination of reserve categories related to our existing producing properties, as well as estimated quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil related to undeveloped discoveries if, in our judgment, it is likely that development plans will be approved in the foreseeable future. Assumptions regarding our ability to realize the U.S. federal benefit of foreign tax credits are based on certain estimates concerning future operating conditions (particularly as related to crude oil and condensate, NGLs, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the year that such credits may be claimed.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and
- health care cost projections.

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our U.S. pension plans and our other U.S. postretirement benefit plans due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least $250 million par value outstanding. The constructed yield curve is based on those bonds representing the 50 percent highest yielding issuances within each defined maturity group.

Of the assumptions used to measure obligations and estimated annual net periodic benefit cost as of December 31, the discount rate has the most significant effect on the periodic benefit cost reported for the plans. The hypothetical impacts of a 0.25 percent change in the discount rates of 3.71 percent for our U.S. pension plans and 4.01 percent for our other U.S. postretirement benefit plans is summarized in the table below:

	Impact of a 0.25 Percent Increase in Discount Rate		Impact of a 0.25 Percent Decrease in Discount Rate	
(In millions)	Obligation	Expense	Obligation	Expense
U.S. pension plans	$ (35)	$ (4)	$ 37	$ 4
Other U.S. postretirement benefit plans	$ (7)	$ -	$ 8	$ -

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55 percent equity and 45 percent other fixed income securities), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields. Decreasing the 6.75 percent asset rate of return assumption by 0.25 would not have a significant impact on our defined benefit pension expense.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans. Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data - Note 19 to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the consolidated balance sheets.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation, additional information on the extent and nature of site contamination and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances outside legal counsel is utilized.

We generally record losses related to these types of contingencies as other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income. For additional information on contingent liabilities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

See Item 8. Financial Statements and Supplementary Data - Note 2 to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil and condensate, NGL, natural gas and synthetic crude oil prices. We are also exposed to market risks related to changes in interest rates and foreign currency exchange rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

See Item 8. Financial Statements and Supplementary Data - Notes 14 and 15 to the consolidated financial statements for more information about the fair value measurement of our derivatives, the amounts recorded in our consolidated balance sheets and statements of income and the related notional amounts.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will periodically protect prices on forecasted sales, as deemed appropriate. We may use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our business. Our consolidated results for 2013 and 2012 were impacted by crude oil derivatives related to a portion of our North America E&P crude oil sales, all of which expired in December 2013. There were no crude oil derivatives in 2014.

Interest Rate Risk

At December 31, 2014, our portfolio of long-term debt was substantially comprised of fixed rate instruments. We currently manage our exposure to interest rate movements by utilizing interest rate swap agreements that effectively convert a portion of our fixed rate debt to floating interest rate debt. As of December 31, 2014, we had multiple interest rate swap agreements with a total notional of $900 million designated as fair value hedges.

Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value. Sensitivity analysis of the incremental effect of a hypothetical 10 percent change in interest rates on financial assets and liabilities as of December 31, 2014, is provided in the following table.

(In millions)	Fair Value	Incremental Change in Fair Value
Financial assets (liabilities): [a]		
Interest rate swap agreements	$ 8 [b]	$ 2
Long-term debt, including amounts due within one year	$ (6,887) [b][c]	$ (216)

(a) Fair values of cash and cash equivalents, receivables, commercial paper, accounts payable and accrued interest approximate carrying value and are relatively insensitive to changes in interest rates due to the short-term maturity of the instruments. Accordingly, these instruments are excluded from the table.
(b) Fair value was based on market prices where available, or current borrowing rates for financings with similar terms and maturities.
(c) Excludes capital leases.

Foreign Currency Exchange Rate Risk

We may manage our exposure to foreign currency exchange rates by utilizing forward and option contracts. The primary objective of this program is to reduce our exposure to movements in foreign currency exchange rates by locking in such rates. As of December 31, 2014, we had no open derivatives related to foreign currency exchange rates.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices remain at or fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

Item 8. Financial Statements and Supplementary Data

Index

Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon Oil") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Lee M. Tillman	/s/ John R. Sult
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) - 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil's management concluded that its internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Lee M. Tillman	/s/ John R. Sult
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Report of Independent Registered Public Accounting Firm

To the Stockholders of Marathon Oil Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Marathon Oil Corporation and its subsidiaries (the "Company") at December 31, 2014, and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework* - 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2015

MARATHON OIL CORPORATION
Consolidated Statements of Income

	Year Ended December 31,		
(In millions, except per share data)	2014	2013	2012
Revenues and other income:			
Sales and other operating revenues, including related party	$ 8,736	$ 9,246	$ 9,237
Marketing revenues	2,110	2,079	2,729
Income from equity method investments	424	423	370
Net gain (loss) on disposal of assets	(90)	(29)	127
Other income	78	64	23
Total revenues and other income	11,258	11,783	12,486
Costs and expenses:			
Production	2,246	2,156	2,079
Marketing, including purchases from related parties	2,105	2,076	2,734
Other operating	462	389	364
Exploration	793	891	685
Depreciation, depletion and amortization	2,861	2,500	2,008
Impairments	132	96	371
Taxes other than income	406	345	243
General and administrative	654	659	676
Total costs and expenses	9,659	9,112	9,160
Income from operations	1,599	2,671	3,326
Net interest and other	(238)	(278)	(222)
Income from continuing operations before income taxes	1,361	2,393	3,104
Provision for income taxes	392	1,462	2,248
Income from continuing operations	969	931	856
Discontinued operations	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Per Share Data			
Basic:			
Income from continuing operations	$ 1.42	$ 1.32	$ 1.21
Discontinued operations	$ 3.06	$ 1.17	$ 1.03
Net income	$ 4.48	$ 2.49	$ 2.24
Diluted:			
Income from continuing operations	$ 1.42	$ 1.31	$ 1.21
Discontinued operations	$ 3.04	$ 1.16	$ 1.02
Net income	$ 4.46	$ 2.47	$ 2.23
Dividends	$ 0.80	$ 0.72	$ 0.68
Weighted average shares:			
Basic	680	705	706
Diluted	683	709	710

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
(In millions)	2014	2013	2012
Net income	$ 3,046	$ 1,753	$ 1,582
Other comprehensive income (loss)			
Postretirement and postemployment plans			
Change in actuarial loss and other	(52)	300	(97)
Income tax benefit (provision)	25	(112)	35
Postretirement and postemployment plans, net of tax	(27)	188	(62)
Derivative hedges			
Net unrecognized gain	1	1	1
Income tax provision	-	-	-
Derivative hedges, net of tax	1	1	1
Foreign currency translation and other			
Unrealized gain (loss)	-	(3)	1
Income tax benefit (provision)	(1)	1	(3)
Foreign currency translation and other, net of tax	(1)	(2)	(2)
Other comprehensive income (loss)	(27)	187	(63)
Comprehensive income	$ 3,019	$ 1,940	$ 1,519

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Balance Sheets

	December 31,	
(In millions, except par values and share amounts)	2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$ 2,398	$ 264
Receivables, less reserve of $3 and $0	1,729	2,134
Inventories	357	364
Other current assets	109	213
Total current assets	4,593	2,975
Equity method investments	1,113	1,201
Property, plant and equipment, less accumulated depreciation,		
depletion and amortization of $21,884 and $21,895	29,040	28,145
Goodwill	459	499
Other noncurrent assets	806	2,800
Total assets	$ 36,011	$ 35,620
Liabilities		
Current liabilities:		
Commercial paper	$ -	$ 135
Accounts payable	2,545	2,206
Payroll and benefits payable	191	240
Accrued taxes	285	1,445
Other current liabilities	290	239
Long-term debt due within one year	1,068	68
Total current liabilities	4,379	4,333
Long-term debt	5,323	6,394
Deferred tax liabilities	2,486	2,492
Defined benefit postretirement plan obligations	598	604
Asset retirement obligations	1,917	2,009
Deferred credits and other liabilities	288	444
Total liabilities	14,991	16,276
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - no shares issued or outstanding (no par value,		
26 million shares authorized)	-	-
Common stock:		
Issued - 770 million shares (par value $1 per share, 1.1 billion shares authorized)	770	770
Securities exchangeable into common stock - no shares issued		
or outstanding (no par value, 29 million shares authorized)	-	-
Held in treasury, at cost - 95 million and 73 million shares	(3,642)	(2,903)
Additional paid-in capital	6,531	6,592
Retained earnings	17,638	15,135
Accumulated other comprehensive loss	(277)	(250)
Total stockholders' equity	21,020	19,344
Total liabilities and stockholders' equity	$ 36,011	$ 35,620

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

	Year Ended December 31,		
(In millions)	2014	2013	2012
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income	$ 3,046	$ 1,753	$ 1,582
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations	(2,077)	(822)	(726)
Deferred income taxes	88	(34)	(34)
Depreciation, depletion and amortization	2,861	2,500	2,008
Impairments	132	96	371
Pension and other postretirement benefits, net	(34)	45	(32)
Exploratory dry well costs and unproved property impairments	623	720	457
Net (gain) loss on disposal of assets	90	29	(127)
Equity method investments, net	27	12	11
Changes in:			
Current receivables	119	217	(481)
Inventories	(11)	(19)	(24)
Current accounts payable and accrued liabilities	(33)	(208)	(102)
All other operating, net	(95)	99	(29)
Net cash provided by continuing operations	4,736	4,388	2,874
Net cash provided by discontinued operations	751	882	1,143
Net cash provided by operating activities	5,487	5,270	4,017
Investing activities:			
Acquisitions, net of cash acquired	(21)	(74)	(1,033)
Additions to property, plant and equipment	(5,160)	(4,443)	(4,361)
Disposal of assets, net of cash transferred to buyer	3,760	450	467
Investments - return of capital	61	61	57
Investing activities of discontinued operations	(376)	(550)	(579)
All other investing, net	(10)	35	10
Net cash used in investing activities	(1,746)	(4,521)	(5,439)
Financing activities:			
Commercial paper, net	(135)	(65)	200
Borrowings	-	-	1,997
Debt issuance costs	-	-	(21)
Debt repayments	(68)	(182)	(145)
Purchases of common stock	(1,000)	(500)	-
Dividends paid	(543)	(508)	(480)
All other financing, net	153	93	49
Net cash provided by (used in) financing activities	(1,593)	(1,162)	1,600
Effect of exchange rate changes on cash:			
Continuing operations	(2)	(3)	7
Discontinued operations	(12)	(4)	6
Net increase (decrease) in cash and cash equivalents	2,134	(420)	191
Cash and cash equivalents at beginning of period	264	684	493
Cash and cash equivalents at end of period	$ 2,398	$ 264	$ 684

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

	Total Equity of Marathon Oil Stockholders								
(In millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Equity
December 31, 2011 Balance	$ -	$ 770	$ -	$ (2,716)	$ 6,680	$ 12,788	$ (370)	$ 7	$ 17,159
Shares issued - stock-based compensation	-	-	-	164	(75)	-	-	-	89
Shares repurchased	-	-	-	(8)	-	-	-	-	(8)
Stock-based compensation	-	-	-	-	22	-	-	-	22
Net income	-	-	-	-	-	1,582	-	-	1,582
Other comprehensive income	-	-	-	-	-	-	(63)	-	(63)
Dividends paid	-	-	-	-	-	(480)	-	-	(480)
Purchase of shares from noncontrolling interest	-	-	-	-	-	-	-	(7)	(7)
Other					(11)				(11)
December 31, 2012 Balance	$ -	$ 770	$ -	$ (2,560)	$ 6,616	$ 13,890	$ (433)	$ -	$ 18,283
Shares issued - stock-based compensation	-	-	-	170	(44)	-	-	-	126
Shares repurchased	-	-	-	(513)	-	-	-	-	(513)
Stock-based compensation	-	-	-	-	20	-	-	-	20
Net income	-	-	-	-	-	1,753	-	-	1,753
Other comprehensive loss	-	-	-	-	-	-	183	-	183
Dividends paid	-	-	-	-	-	(508)	-	-	(508)
December 31, 2013 Balance	$ -	$ 770	$ -	$ (2,903)	$ 6,592	$ 15,135	$ (250)	$ -	$ 19,344
Shares issued - stock-based compensation	-	-	-	276	(57)	-	-	-	219
Shares repurchased	-	-	-	(1,015)	-	-	-	-	(1,015)
Stock-based compensation	-	-	-	-	(4)	-	-	-	(4)
Net income	-	-	-	-	-	3,046	-	-	3,046
Other comprehensive income	-	-	-	-	-	-	(27)	-	(27)
Dividends paid	-	-	-	-	-	(543)	-	-	(543)
December 31, 2014 Balance	$ -	$ 770	$ -	$ (3,642)	$ 6,531	$ 17,638	$ (277)	$ -	$ 21,020

(Shares in millions)	Preferred Stock	Common Stock	Securities Exchangeable into Common Stock	Treasury Stock
December 31, 2011 Balance	-	770	-	66
Shares issued - stock-based compensation	-	-	-	(3)
December 31, 2012 Balance	-	770	-	63
Shares issued - stock-based compensation	-	-	-	(4)
Shares repurchased	-	-	-	14
December 31, 2013 Balance	-	770	-	73
Shares issued - stock-based compensation	-	-	-	(7)
Shares repurchased	-	-	-	29
December 31, 2014 Balance	-	770	-	95

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Principal Accounting Policies

We are a global energy company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.; and oil sands mining, bitumen transportation and upgrading, and marketing of synthetic crude oil and vacuum gas oil in Canada.

Principles applied in consolidation - These consolidated financial statements include the accounts of our majority-owned, controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

Equity method investments - Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees.

Equity method investments are included as noncurrent assets on the consolidated balance sheet. These investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in net income. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into net income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Discontinued operations - Disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated. As a result of the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014 (see Note 5), these businesses are reflected as discontinued operations in all periods presented.

Use of estimates - The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Foreign currency transactions - The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition - Revenues are recognized when products are shipped or services are provided to customers, title is transferred, the sales price is fixed or determinable and collectability is reasonably assured. We follow the sales method of accounting for crude oil and natural gas production imbalances and would recognize a liability if our existing proved reserves were not adequate to cover an imbalance. Imbalances have not been significant in the periods presented.

In the lower 48 states of the U.S., production volumes of crude oil and condensate, NGLs and natural gas are generally sold immediately and transported to market. In international locations, liquid hydrocarbon production volumes may be stored as inventory and sold at a later time. In Canada, mined bitumen is first processed through an upgrader and then sold as synthetic crude oil.

Cash and cash equivalents - Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable - The majority of our receivables are from joint interest owners in properties we operate or from purchasers of commodities, both of which are recorded at invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. Uncollectible accounts receivable are reserved against the allowance for uncollectible accounts when it is determined the receivable will not be collected and the amount of any reserve may be reasonably estimated.

Inventories - Crude oil and natural gas inventories are recorded at weighted average cost and carried at the lower of cost or market value. The last-in, first-out ("LIFO") method is used for our U.S. crude oil and natural gas inventories. Materials and supplies inventory consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments - We may use derivatives to manage a portion of our exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk. All derivative instruments are recorded at fair value. Commodity derivatives and interest rate swaps are reflected on our consolidated balance sheet on a net basis by counterparty, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, foreign currency risk and interest rate risk are classified in operating activities with the underlying transactions. Our derivative instruments contain no significant contingent credit features.

Fair value hedges - We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio and foreign currency forwards to manage our exposure to changes in the value of foreign currency denominated tax liabilities. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Derivatives not designated as hedges - Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price risk on the forecasted sale of crude oil, natural gas and synthetic crude oil that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk - All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Fair value transfer - We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. If significant transfers occur, they would be disclosed in Note 14 to the consolidated financial statements.

Property, plant and equipment - We use the successful efforts method of accounting for oil and gas producing activities, which include bitumen mining and upgrading.

Property acquisition costs - Costs to acquire mineral interests in oil and natural gas properties or in oil sands mines, to drill and equip exploratory wells in progress and those that find proved reserves, to drill and equip development wells and to construct or expand oil sands mines and upgrading facilities are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended exploratory well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization - Capitalized costs to acquire oil and natural gas properties, which include bitumen mining and upgrading facilities, are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets as summarized below.

Type of Asset	Range of Useful Lives
Office furniture, equipment and computer hardware	1 to 15 years
Pipelines	10 to 40 years
Plants, facilities, mine equipment and infrastructure	16 to 40 years

Impairments - We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells, development costs and our bitumen mining and upgrading facilities, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared

infrastructure. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, the expense is reported in exploration expenses.

Dispositions - When property, plant and equipment depreciated on an individual basis is sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill - Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to impairments.

Major maintenance activities - Costs for planned major maintenance are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.

Environmental costs - We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed or reliably determinable. Environmental expenditures are capitalized only if the costs mitigate or prevent future contamination or if the costs improve the environmental safety or efficiency of the existing assets.

Asset retirement obligations - The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities, which include our bitumen mining facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, mine assets, gathering systems, wells and related structures and restoration costs of land and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals. Asset retirement obligations have not been recognized for certain of our international oil and gas producing facilities as we currently do not have a legal obligation associated with the retirement of those facilities. Asset retirement obligations have not been recognized for the removal of materials and equipment from or the closure of certain bitumen upgrading assets because the fair value cannot be reasonably estimated since the settlement dates of the obligations are indeterminate.

Inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for oil and gas production facilities, which include our bitumen mining facilities, while accretion escalates over the lives of the assets.

Deferred income taxes - Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include our expectation to generate sufficient future taxable income including future foreign source income, tax credits, operating loss carryforwards and management's intent regarding the permanent reinvestment of the income from certain foreign subsidiaries.

Stock-based compensation arrangements - The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected life of the stock option award and the expected volatility of

our stock price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders' equity when restricted stock awards are granted.

The fair value of our stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods.

2. Accounting Standards

Not Yet Adopted

In February 2015, the FASB issued an amendment to the guidance for determining whether an entity is a variable interest entity ("VIE"). The standard does not add or remove any of the five characteristics that determine if an entity is a VIE. However, it does change the manner in which a reporting entity assesses one of the characteristics. In particular, when decision-making over the entity's most significant activities has been outsourced, the standard changes how a reporting entity assesses if the equity holders at risk lack decision making rights. This standard is effective for us for annual periods beginning after December 15, 2015 and early adoption is permitted, including in interim periods. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In August 2014, the FASB issued an update that requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards. This standard is effective for us in the first quarter of 2017 and early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

In May 2014, the FASB issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in the first quarter of 2017 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is not permitted. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In April 2014, the FASB issued an amendment to accounting standards that changes the criteria for reporting discontinued operations while enhancing related disclosures. Under the amendment, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Expanded disclosures about the assets, liabilities, income and expenses of discontinued operations will be required. In addition, disclosure of the pretax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting will be made in order to provide users with information about the ongoing trends in an organization's results from continuing operations. The amendments are effective for us in the first quarter of 2015 and early adoption is permitted. We did not elect early adoption of this amendment and do not expect its future adoption to have a significant impact on our consolidated results of operations, financial position or cash flows.

Recently Adopted

In June 2013, the FASB ratified the Emerging Issues Task Force consensus which requires that an unrecognized tax benefit (or a portion thereof) be presented as a reduction to a deferred tax asset for an available net operating loss carryforward, a similar tax loss or tax credit carryforward. This accounting standards update was effective for us beginning in the first quarter of 2014 and is required to be applied prospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies,

guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. This accounting standards update was effective for us beginning in the first quarter of 2014 and is required to be applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. Variable Interest Entities

The owners of the AOSP, in which we hold a 20 percent undivided interest, contracted with a wholly owned subsidiary of a publicly traded Canadian limited partnership ("Corridor Pipeline") to provide materials transportation capabilities among the Muskeg River and Jackpine mines, the Scotford upgrader and markets in Edmonton. The contract, originally signed in 1999 by a company we acquired, allows each holder of an undivided interest in the AOSP to ship materials in accordance with its undivided interest. Costs under this contract are accrued and recorded on a monthly basis, with a $3 million current liability recorded at December 31, 2014 and 2013. Under this agreement, the AOSP absorbs all of the operating and capital costs of the pipeline. Currently, no third-party shippers use the pipeline. Should shipments be suspended, by choice or due to force majeure, we remain responsible for the portion of the payments related to our undivided interest for all remaining periods. The contract expires in 2029; however, the shippers can extend its term perpetually. This contract qualifies as a variable interest contractual arrangement and the Corridor Pipeline qualifies as a VIE. We hold a variable interest but are not the primary beneficiary because our shipments are only 20 percent of the total; therefore the Corridor Pipeline is not consolidated by us. Our maximum exposure to loss as a result of our involvement with this VIE is the amount we expect to pay over the contract term, which was $558 million as of December 31, 2014. The liability on our books related to this contract at any given time will reflect amounts due for the immediately previous month's activity, which is substantially less than the maximum exposure over the contract term. We have not provided financial assistance to Corridor Pipeline and we do not have any guarantees of such assistance in the future.

4. Acquisitions

2014 - North America E&P

In an asset acquisition that closed August 2014, we added acreage to the Oklahoma Resource Basins at a cost of approximately $80 million before final settlement adjustments.

In the fourth quarter of 2014, we acquired additional acres in the SCOOP, at a cost of approximately $60 million before final settlement adjustments.

2013 & 2012 - North America E&P

In July 2013, we acquired additional acreage in the Eagle Ford in a transaction valued at $97 million, including a carried interest of $23 million which was fully satisfied in 2014. The transaction was accounted for as a business combination, with the entire up-front cash consideration of $74 million allocated to property, plant and equipment at the acquisition date.

During 2012, we acquired approximately 25,000 net acres in the core of the Eagle Ford in several transactions accounted for as business combinations. The largest transactions were the acquisitions of Paloma Partners II, LLC, which closed in the second quarter of 2012 for cash consideration of $768 million, and an acquisition of proved and unproved properties that closed in the third quarter of 2012 for cash consideration of $232 million.

The following table summarizes the amounts allocated to the assets acquired and liabilities assumed based upon their fair values at the acquisition dates:

	Closed in Quarter Ended	
(In millions)	June 30, 2012	September 30, 2012
Current assets:		
Cash	$ 8	$ -
Receivables	22	8
Inventories	1	-
Total current assets acquired	31	8
Property, plant and equipment	822	248
Total assets acquired	853	256
Current liabilities:		
Accounts payable	78	23
Total current liabilities assumed	78	23
Asset retirement obligations	7	1
Total liabilities assumed	85	24
Net assets acquired	$ 768	$ 232

The fair values of assets acquired and liabilities assumed in each of these business combinations were measured primarily using an income approach, specifically utilizing a discounted cash flow analysis. The estimated fair values were based on significant inputs not observable in the market, and therefore represent Level 3 measurements. Significant inputs included estimated reserve volumes, the expected future production profile, estimated commodity prices and assumptions regarding future operating and development costs and a discount rate of approximately 10 percent. The pro forma impact of these transactions, individually and in the aggregate, is not material to our consolidated statements of income for any periods presented.

5. Dispositions

2014 - International E&P

In June 2014, we entered into an agreement to sell our Norway business, including the operated Alvheim FPSO, 10 operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea, with an effective date of January 1, 2014. The transaction closed in the fourth quarter of 2014 for proceeds of $2.1 billion, before netting $589 million cash transferred to the buyer. A $976 million after-tax gain on the sale of Norway business was recorded in the fourth quarter of 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

As part of our agreement to sell our Norway business, we agreed to provide customary transition services to the buyer for an initial period of six months from the closing date. The buyer may extend such services for an additional six months if mutually agreed upon. These services include accounting, marketing, information technology and safety. Amounts received for these transition services are not significant to us. We do not exert influence over the operational and financial policies of the Norway business nor do we retain risk associated with this business.

Our Norway business is reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues applicable to discontinued operations	$ 1,981	$ 3,176	$ 3,726
Pretax income from discontinued operations	$ 1,693	$ 2,537	$ 3,026
Pretax gain on disposition of discontinued operations	$ 1,406	$ -	$ -

In the first quarter of 2014, we closed the sales of our 10 percent non-operated working interests in the Production Sharing Contracts and Joint Operating Agreements for Angola Blocks 31 and 32 for aggregate proceeds of approximately $2 billion. A $532 million after-tax gain on the sale of our Angola assets was recorded in 2014. Included in this after-tax gain is a deferred tax benefit reflecting our ability to utilize foreign tax credits that otherwise would have needed a valuation allowance.

Our Angola operations are reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. Select amounts reported in discontinued operations were as follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Revenues applicable to discontinued operations	$ 58	$ 361	$ -
Pretax income (loss) from discontinued operations	$ 51	$ 247	$ (17)
Pretax gain on disposition of discontinued operations	$ 426	$ -	$ -

Assets held for sale in the December 31, 2013 consolidated balance sheet were related to the Angola Block 31 disposition that was pending at that date and included:

(In millions)	December 31, 2013
Other current assets	$ 41
Other noncurrent assets	1,647
Total assets	$ 1,688
Other current liabilities	$ 25
Deferred credits and other liabilities	43
Total liabilities	$ 68

2014 - North America E&P

In June 2014, we closed the sale of non-core acreage located in the far northwest portion of the Williston Basin for proceeds of $90 million. A pretax loss of $91 million was recorded in the second quarter of 2014.

2013 - International E&P

In the fourth quarter of 2013, we transferred our 45 percent working interest and operatorship in the Safen block in the Kurdistan Region of Iraq at a pretax loss of $17 million.

2013 - North America E&P

In June 2013, we closed the sale of our interests in the DJ Basin for proceeds of $19 million. A pretax loss of $114 million was recorded in the second quarter of 2013.

In February 2013, we conveyed our interests in the Marcellus natural gas shale play to the operator. A $43 million pretax loss was recorded in the first quarter of 2013.

In February 2013, we closed the sale of our interest in the Neptune gas plant, located onshore Louisiana, for proceeds of $166 million. A $98 million pretax gain was recorded in the first quarter of 2013.

In January 2013, we closed the sale of our remaining assets in Alaska, for proceeds of $195 million, subject to a six-month escrow of $50 million which was collected in July 2013. After closing adjustments were made in the second quarter of 2013, the pretax gain on this sale was $55 million.

2012 - International E&P

In May 2012, we executed agreements to relinquish our operatorship of and participating interests in the Bone Bay and Kumawa exploration licenses in Indonesia. As a result, we reported a $36 million pretax loss on disposal of assets.

2012 - North America E&P

In the third quarter of 2012, we sold non-core net undeveloped acres in the Eagle Ford for proceeds of $9 million. A pretax loss of $18 million was recorded.

In January 2012, we closed on the sale of our interests in several Gulf of Mexico crude oil pipeline systems for proceeds of $206 million. This included our equity method interests in Poseidon Oil Pipeline Company, L.L.C. and Odyssey Pipeline

L.L.C., as well as certain other oil pipeline interests, including the Eugene Island pipeline system. A pretax gain of $166 million was recorded in the first quarter of 2012.

6. Income per Common Share

Basic income per share is based on the weighted average number of common shares outstanding. Diluted income per share assumes exercise of stock options in all years and stock appreciation rights in 2013 and 2012, provided the effect is not antidilutive. The per share calculations below exclude 4 million, 5 million and 10 million stock options in 2014, 2013 and 2012 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	2014	2013	2012
Income from continuing operations	$ 969	$ 931	$ 856
Discontinued operations	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Weighted average common shares outstanding	680	705	706
Effect of dilutive securities	3	4	4
Weighted average common shares, diluted	683	709	710
Per basic share:			
Income from continuing operations	$ 1.42	$ 1.32	$ 1.21
Discontinued operations	$ 3.06	$ 1.17	$ 1.03
Net income	$ 4.48	$ 2.49	$ 2.24
Per diluted share:			
Income from continuing operations	$ 1.42	$ 1.31	$ 1.21
Discontinued operations	$ 3.04	$ 1.16	$ 1.02
Net income	$ 4.46	$ 2.47	$ 2.23

7. Segment Information

We have three reportable operating segments. Each of these segments is organized and managed based upon both geographic location and the nature of the products and services it offers:

- North America E&P ("N.A. E&P") - explores for, produces and markets crude oil and condensate, NGLs and natural gas in North America;
- International E&P ("Int'l E&P") - explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of North America and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.; and
- Oil Sands Mining ("OSM") - mines, extracts and transports bitumen from oil sands deposits in Alberta, Canada, and upgrades the bitumen to produce and market synthetic crude oil and vacuum gas oil.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker ("CODM"). Segment income represents income from continuing operations excluding certain items not allocated to segments, net of income taxes, attributable to the operating segments. Our corporate and operations support general and administrative costs are not allocated to the operating segments. These costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Gains or losses on dispositions, certain impairments, unrealized gains or losses on crude oil derivative instruments, or other items that affect comparability (as determined by the CODM) also are not allocated to operating segments.

As discussed in Note 5, we closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are reflected as discontinued operations and excluded from the International E&P segment in all periods presented.

Year Ended December 31, 2014				Not Allocated	
(In millions)	N.A. E&P	Int'l E&P	OSM	to Segments	Total
Sales and other operating revenues	$ 5,770	$ 1,410	$ 1,556	$ -	$ 8,736
Marketing revenues	1,839	219	52	-	2,110
Total revenues	7,609	1,629	1,608	-	10,846
Income from equity method investments	-	424	-	-	424
Net gain (loss) on disposal of assets and other income	23	57	4	(96) [c]	(12)
Less:					
Production expenses	891	386	969	-	2,246
Marketing costs	1,836	217	52	-	2,105
Exploration expenses	608	185	-	-	793
Depreciation, depletion and amortization	2,342	269	206	44	2,861
Impairments	23	-	-	109 [d]	132
Other expenses [a]	473	197	54	392 [e]	1,116
Taxes other than income	385	-	20	1	406
Net interest and other	-	-	-	238	238
Income tax provision (benefit)	381	288	76	(353)	392
Segment income/Income from continuing operations	$ 693	$ 568	$ 235	$ (527)	$ 969
Capital expenditures [b]	$ 4,698	$ 534	$ 212	$ 51	$ 5,495

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Primarily related to the sale of non-core acreage from our North America E&P segment (see Note 5).
[d] Proved property impairments (see Note 14).
[e] Includes pension settlement loss of $99 million (see Note 19).

Year Ended December 31, 2013				Not Allocated	
(In millions)	N.A. E&P	Int'l E&P	OSM	to Segments	Total
Sales and other operating revenues	$ 5,068	$ 2,654	$ 1,576	$ (52) [c]	$ 9,246
Marketing revenues	1,797	264	18	-	2,079
Total revenues	6,865	2,918	1,594	(52)	11,325
Income from equity method investments	-	427	-	(4) [d]	423
Net gain (loss) on disposal of assets and other income	12	50	5	(32) [e]	35
Less:					
Production expenses	797	359	1,000	-	2,156
Marketing costs	1,796	262	18	-	2,076
Exploration expenses	725	166	-	-	891
Depreciation, depletion and amortization	1,927	331	218	24	2,500
Impairments	41	-	-	55 [f]	96
Other expenses [a]	420	161	66	401 [g]	1,048
Taxes other than income	318	-	22	5	345
Net interest and other	-	-	-	278	278
Income tax provision (benefit)	324	1,358	69	(289)	1,462
Segment income/Income from continuing operations	$ 529	$ 758	$ 206	$ (562)	$ 931
Capital expenditures [b]	$ 3,649	$ 456	$ 286	$ 58	$ 4,449

[a] Includes other operating expenses and general and administrative expenses.
[b] Includes accruals.
[c] Unrealized loss on crude oil derivative instruments (see Note 15).
[d] EGHoldings impairment (see Note 14).
[e] Related to the disposal of assets from our North America E&P segment (see Note 5).
[f] Proved property impairments (see Note 14).
[g] Includes pension settlement loss of $45 million (see Note 19).

Year Ended December 31, 2012 *(In millions)*	N.A. E&P	Int'l E&P	OSM	Not Allocated to Segments	Total
Sales and other operating revenues	$ 3,944	$ 3,719	$ 1,521	$ 53 (c)	$ 9,237
Marketing revenues	2,451	248	30	-	2,729
Total revenues	6,395	3,967	1,551	53	11,966
Income from equity method investments	2	368	-	-	370
Net gain (loss) on disposal of assets and other income	11	21	4	114 (d)	150
Less:					
Production expenses	706	377	996	-	2,079
Marketing costs	2,444	259	31	-	2,734
Exploration expenses	588	97	-	-	685
Depreciation, depletion and amortization	1,428	318	217	45	2,008
Impairments	11	-	-	360 (e)	371
Other expenses (a)	400	116	60	464 (f)	1,040
Taxes other than income	226	-	22	(5)	243
Net interest and other	-	-	-	222	222
Income tax provision (benefit)	223	2,294	58	(327)	2,248
Segment income/Income from continuing operations	$ 382	$ 895	$ 171	$ (592)	$ 856
Capital expenditures (b)	$ 3,988	$ 235	$ 188	$ 115	$ 4,526

(a) Includes other operating expenses and general and administrative expenses.
(b) Includes accruals.
(c) Unrealized gain on crude oil derivative instruments (see Note 15).
(d) Related to the disposal of assets from our North America E&P and International E&P segments (see Note 5).
(e) Proved property impairments (see Note 14).
(f) Includes pension settlement loss of $45 million (see Note 19).

Revenues from external customers are attributed to geographic areas based upon selling location. The following summarizes revenues from external customers by geographic area.

	Year Ended December 31,		
(In millions)	2014	2013	2012
United States	$ 7,609	$ 6,813	$ 6,448
Canada	1,608	1,594	1,551
Libya(a)	244	1,106	1,989
Other international	1,385	1,812	1,978
Total revenues	$ 10,846	$ 11,325	$ 11,966

(a) See Note 12 for discussion of Libya operations.

In 2014, sales to Shell Oil and its affiliates accounted for approximately 10 percent of our total revenues. In 2013, Statoil, the purchaser of the majority of our Libyan crude oil, accounted for approximately 10 percent of our total revenues. In 2012, Statoil accounted for approximately 15 percent of our total revenues, while sales to Shell Oil and its affiliates accounted for approximately 12 percent of total revenues.

Revenues by product line were:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Crude oil and condensate	$ 8,170	$ 8,688	$ 9,301
Natural gas liquids	371	313	201
Natural gas	693	693	835
Synthetic crude oil	1,525	1,542	1,409
Other	87	89	220
Total revenues	$ 10,846	$ 11,325	$ 11,966

The following summarizes certain long-lived assets by geographic area, including property, plant and equipment and equity method investments.

	December 31,	
(In millions)	2014	2013
United States	$ 16,518	$ 14,635
Canada	9,802	9,794
Norway [(a)]	-	977
Equatorial Guinea	1,949	1,977
Other international	1,884	1,963
Total long-lived assets	$ 30,153	$ 29,346

[(a)] Decrease in 2014 is due to the previously discussed sale of our Norway business.

8. Other Items

Net interest and other

	Year Ended December 31,		
(In millions)	2014	2013	2012
Interest:			
Interest income	$ 7	$ 5	$ 12
Interest expense	(297)	(299)	(241)
Income on interest rate swaps	12	9	7
Interest capitalized	20	12	9
Total interest	(258)	(273)	(213)
Other:			
Net foreign currency gains	21	14	2
Write off of contingent proceeds	-	(4)	-
Other	(1)	(15)	(11)
Total other	20	(5)	(9)
Net interest and other	$ (238)	$ (278)	$ (222)

Foreign currency transactions - Aggregate foreign currency gains were included in the consolidated statements of income as follows:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Net interest and other	$ 21	$ 14	$ 2
Provision for income taxes	(12)	(2)	2
Aggregate foreign currency gains	$ 9	$ 12	$ 4

9. Income Taxes

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2014			2013			2012		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ 15	$ 62	$ 77	$ 83	$ (47)	$ 36	$ (47)	$ 43	$ (4)
State and local	8	(58)	(50)	39	(6)	33	(34)	48	14
Foreign	281	84	365	1,374	19	1,393	2,363	(125)	2,238
Total	$ 304	$ 88	$ 392	$ 1,496	$ (34)	$ 1,462	$ 2,282	$ (34)	$ 2,248

A reconciliation of the federal statutory income tax rate applied to income from continuing operations before income taxes to the provision for income taxes follows:

	Year Ended December 31,		
	2014	2013	2012
Statutory rate applied to income from continuing operations before income taxes	35%	35%	35%
Effects of foreign operations, including foreign tax credits	(6)	26	36
Change in permanent reinvestment assertion	(19)	-	-
Adjustments to valuation allowances	21	(1)	-
Other	(2)	1	1
Effective income tax rate on continuing operations	29%	61%	72%

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments appears in the "Not Allocated to Segments" column of the tables in Note 7.

Effects of foreign operations - The effects of foreign operations on our effective tax rate decreased in 2014 and 2013 as compared to 2012, due to a shift in pretax income mix between high and low tax jurisdictions. This is primarily related to decreased sales in Libya in 2014 and 2013 where the tax rate is in excess of 90 percent. Excluding Libya, the effective tax rates on continuing operations for 2014, 2013 and 2012 would be 27 percent, 38 percent and 37 percent.

Change in permanent reinvestment assertion - In the second quarter of 2014, we reviewed our foreign operations, including the disposition of our Norway business, and concluded that our foreign operations do not have the same level of immediate capital needs as previously expected. Therefore, we no longer intend for previously unremitted foreign earnings associated with our U.K. operations to be permanently reinvested outside the U.S. The U.K. statutory tax rate is in excess of the U.S. statutory tax rate and therefore foreign tax credits associated with these earnings exceeds any incremental U.S. tax liabilities.

Adjustments to valuation allowances - In 2014, we increased the valuation allowance against foreign tax credits as a result of removing the permanent reinvestment assertion on our U.K. operations since the U.K. statutory tax rate is in excess of the U.S. statutory tax rate per discussion above. In 2013, valuation allowances decreased primarily due to the disposal of our Indonesian assets.

Deferred tax assets and liabilities resulted from the following:

	Year Ended December 31,	
(In millions)	2014	2013
Deferred tax assets:		
Employee benefits	$ 364	$ 387
Operating loss carryforwards	245	284
Capital loss carryforwards	89	3
Foreign tax credits	4,062	5,730
Other	116	95
Valuation allowances:		
Federal	(2,775)	(2,997)
State, net of federal benefit	(58)	(67)
Foreign	(108)	(149)
Total deferred tax assets	1,935	3,286
Deferred tax liabilities:		
Property, plant and equipment	3,737	4,018
Investments in subsidiaries and affiliates	66	794
Other	67	67
Total deferred tax liabilities	3,870	4,879
Net deferred tax liabilities	$ 1,935	$ 1,593

Tax carryforwards - At December 31, 2014 our operating loss carryforwards included $570 million from Canada that expire in 2029 through 2032, $180 million from the Kurdistan Region of Iraq that expire in 2016 through 2019 and $41 million

from E.G. that expire in 2017 through 2019. State operating loss carryforwards of $1,293 million expire in 2015 through 2033. Foreign tax credit carryforwards of $3,550 million expire in 2022 through 2024.

Valuation allowances - The estimated realizability of the benefit of foreign tax credits is based on certain estimates concerning future operating conditions (particularly as related to prevailing liquid hydrocarbon, natural gas and synthetic crude oil prices), future financial conditions, income generated from foreign sources and our tax profile in the years that such credits may be claimed. Federal valuation allowances decreased $222 million in 2014 primarily due to the sale of our Norway and Angola businesses. Federal valuation allowances increased $930 million and $1,277 million in 2013 and 2012, because it is more likely than not that we will be unable to realize all U.S. benefits on foreign taxes accrued in those years.

Foreign valuation allowances decreased $41 million in 2014 primarily due to the disposal of our Angola assets. Foreign valuation allowances decreased $61 million in 2013 primarily due the disposal of our Indonesian assets. Foreign valuation allowances increased $16 million in 2012 primarily due to deferred tax assets generated in the Kurdistan Region of Iraq, Angola and Indonesia.

Net deferred tax liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(In millions)	2014	2013
Assets:		
Other current assets	$ 29	$ 53
Other noncurrent assets	525	847
Liabilities:		
Other current liabilities	3	1
Noncurrent deferred tax liabilities	2,486	2,492
Net deferred tax liabilities	$ 1,935	$ 1,593

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2009 tax year. We believe adequate provision has been made for federal income taxes and interest which may become payable for years not yet settled. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

As of December 31, 2014 our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2004-2013
Canada	2009-2013
Equatorial Guinea	2007-2013
Libya	2012-2013
United Kingdom	2008-2013

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2014	2013	2012
Beginning balance	$ 146	$ 98	$ 157
Additions for tax positions related to the current year	-	14	-
Additions for tax positions of prior years	11	66	81
Reductions for tax positions of prior years	(68)	(25)	(67)
Settlements	(9)	(5)	(72)
Statute of limitations	-	(2)	(1)
Ending balance	$ 80	$ 146	$ 98

If the unrecognized tax benefits as of December 31, 2014 were recognized, $37 million would affect our effective income tax rate. There were $5 million of uncertain tax positions as of December 31, 2014 for which it is reasonably possible that the amount of unrecognized tax benefits would significantly increase or decrease during the next twelve months.

Interest and penalties are recorded as part of the tax provision and were $6 million, $13 million and $4 million related to unrecognized tax benefits in 2014, 2013 and 2012. As of December 31, 2014 and 2013, $16 million and $15 million of interest and penalties were accrued related to income taxes.

Pretax income from continuing operations included amounts attributable to foreign sources of $1,180 million, $2,336 million and $3,356 million in 2014, 2013 and 2012.

Undistributed income of certain Canadian foreign subsidiaries at December 31, 2014 amounted to $1,019 million for which no U.S. deferred income tax provision has been recorded because we intend to permanently reinvest such income in our foreign operations. If such income was not permanently reinvested, income tax expense of approximately $357 million would be recorded, not including potential utilization of foreign tax credits.

10. Inventories

Inventories of liquid hydrocarbons, natural gas and bitumen are carried at the lower of cost or market value. The LIFO method accounted for 6 percent and 4 percent of total inventory value at December 31, 2014 and 2013. Current acquisition costs were estimated to exceed the LIFO inventory value at December 31, 2014 and 2013 by $20 million and $32 million.

	December 31,	
(In millions)	2014	2013
Liquid hydrocarbons, natural gas and bitumen	$ 58	$ 55
Supplies and other items	299	309
Inventories at cost	$ 357	$ 364

11. Equity Method Investments and Related Party Transactions

During 2014, 2013 and 2012 only our equity method investees were considered related parties and they included:

- EGHoldings, in which we have a 60 percent noncontrolling interest. EGHoldings is engaged in LNG production activity.
- Alba Plant LLC, in which we have a 52 percent noncontrolling interest. Alba Plant LLC processes LPG.
- AMPCO, in which we have a 45 percent interest. AMPCO is engaged in methanol production activity.

Our equity method investments are summarized in the following table:

	Ownership as of	December 31,	
(In millions)	December 31, 2014	2014	2013
EGHoldings	60%	$ 693	$ 748
Alba Plant LLC	52%	225	263
AMPCO	45%	194	189
Other investments		1	1
Total		$ 1,113	$ 1,201

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $451 million in 2014, $435 million in 2013 and $381 million in 2012.

Summarized financial information for equity method investees is as follows:

(In millions)		2014		2013		2012
Income data - year:						
Revenues and other income	$	1,349	$	1,444	$	1,330
Income from operations		826		849		755
Net income		728		727		635
Balance sheet data - December 31:						
Current assets	$	639	$	644		
Noncurrent assets		1,461		1,590		
Current liabilities		371		384		
Noncurrent liabilities		39		33		

Revenues from related parties were $56 million, $55 million and $58 million in 2014, 2013 and 2012, with the majority related to EGHoldings in all years. Purchases from related parties were $207 million, $242 million and $248 million in 2014, 2013 and 2012 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2014 and 2013, approximately split evenly between EGHoldings and AMPCO, were $31 million, and $30 million. Payables to related parties were $11 million and $20 million at December 31, 2014 and 2013, with the majority related to Alba Plant LLC.

12. Property, Plant and Equipment

	December 31,			
(In millions)		2014		2013
North America E&P	$	16,717	$	14,973
International E&P [(a)]		2,741		3,590
Oil Sands Mining		9,455		9,447
Corporate		127		135
Net property, plant and equipment	$	29,040	$	28,145

[(a)] International E&P decrease is due to the sale of our Norway business in the fourth quarter of 2014.

Beginning in the third quarter of 2013, our Libya operations were impacted by third-party labor strikes at the Es Sider oil terminal. In early July 2014, Libya's National Oil Corporation rescinded force majeure associated with the third-party labor strikes, and our concession term was extended for slightly more than one year. Although we had five liftings during 2014, in December 2014, Libya's National Oil Corporation once again declared force majeure at Es Sider as disruptions from civil unrest continue. Considerable uncertainty remains around the timing of future production and sales levels.

As of December 31, 2014, our net property, plant and equipment investment in Libya is approximately $771 million, and total proved reserves (unaudited) in Libya are 243 mmboe. We and our partners in the Waha concessions continue to assess the situation and the condition of our assets in Libya. Our periodic assessment of the carrying value of our net property, plant and equipment in Libya specifically considers the net investment in the assets, the duration of our concessions and the reserves anticipated to be recoverable in future periods. The undiscounted cash flows related to our Libya assets continues to exceed the carrying value of $771 million by a material amount.

Deferred exploratory well costs were as follows:

	December 31,		
(In millions)	2014	2013	2012
Amounts capitalized less than one year after completion of drilling	$ 484	$ 512	$ 388
Amounts capitalized greater than one year after completion of drilling	126	281	229
Total deferred exploratory well costs	$ 610	$ 793	$ 617
Number of projects with costs capitalized greater than one year after completion of drilling	3	7	6

(In millions)	2014	2013	2012
Beginning balance	$ 793	$ 617	$ 704
Additions	808	746	699
Dry well expense	(206)	(147)	(111)
Transfers to development	(605)	(414)	(629)
Dispositions[(a)]	(180)	(9)	(46)
Ending balance	$ 610	$ 793	$ 617

(a) We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014.

Exploratory well costs capitalized greater than one year after completion of drilling as of December 31, 2014 are summarized by geographical area below:

(In millions)	
Gabon	$ 66
E.G.	22
Canada	38
Total	$ 126

Well costs that have been suspended for longer than one year are associated with three projects. Management believes these projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development based on current plans.

Gabon - The Diaba-1B well reached total depth in the third quarter of 2013. We are analyzing new 3D seismic, integrated with existing technical data, in order to finalize the next steps in the exploration program on the offshore Diaba License.

E.G. - The Corona well on Block D offshore E.G. was drilled in 2004, and we acquired an additional interest in the well in 2012. We plan to develop Block D through a unitization with the Alba field, which is currently being negotiated and expected to begin in 2015.

Canada - Exploration costs related to our Canadian in-situ assets at Birchwood accumulated 2010 through 2012. In 2012, we submitted a regulatory application for a proposed 12 mbbld SAGD demonstration project. We expect to receive regulatory approval for this project by the end of 2015. Upon receiving this approval, we will further evaluate our development plans.

13. Goodwill

Goodwill is tested for impairment on an annual basis as of April 1 each year, or when events or changes in circumstances indicate the fair value of a reporting unit with goodwill may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only North America E&P and International E&P include goodwill. We estimate the fair values of the North America E&P and International E&P reporting units using an income approach. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. The discounted cash flows that served as the primary basis for the income approach were based on forecasted assumptions. Key assumptions include: future liquid hydrocarbon and natural gas prices, estimated quantities of liquid hydrocarbon and natural gas proved and probable reserves, expected timing of production, discount rates, future capital requirements and operating expenses and tax rates. These assumptions used to determine fair value estimates are consistent with those that management uses to make business decisions. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

We performed our annual impairment tests during 2014, 2013 and 2012 and no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value.

The table below displays the allocated beginning goodwill balances by segment along with changes in the carrying amount of goodwill for 2014 and 2013:

(In millions)	N.A. E&P	Int'l E&P	OSM	Total
2013				
Beginning balance, gross	$ 343	$ 182	$ 1,412	$ 1,937
Less: accumulated impairments	-	-	(1,412)	(1,412)
Beginning balance, net	343	182	-	525
Dispositions	4 [(a)]	(30)	-	(26)
Ending balance, net	$ 347	$ 152	$ -	$ 499
2014				
Beginning balance, gross	$ 347	$ 152	$ 1,412	$ 1,911
Less: accumulated impairments	-	-	(1,412)	(1,412)
Beginning balance, net	347	152	-	499
Dispositions	(3)	(37)	-	(40)
Ending balance, net	$ 344	$ 115	$ -	$ 459

(a) Goodwill related to our Alaska disposition was less than the estimate classified as held for sale in 2012.

After we performed our annual impairment test in April 2014, there was a substantial decline in commodity prices. The resulting change in future commodity price assumptions was a triggering event which required us to reassess our goodwill for impairment as of December 31, 2014. Based on the results of this assessment, we concluded no impairment was required. The fair value of each of our reporting units with goodwill exceeded the book value by a significant amount. A period of sustained reduced commodity prices could result in non-cash impairment charges related to goodwill in future periods.

14. Fair Value Measurements

Fair values - Recurring

The following tables present assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2014 and 2013 by fair value hierarchy level.

	December 31, 2014			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$ -	$ 8	$ -	$ 8
Derivative instruments, assets	$ -	$ 8	$ -	$ 8

	December 31, 2013			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Interest rate	$ -	$ 8	$ -	$ 8
Foreign currency	-	2	-	2
Derivative instruments, assets	$ -	$ 10	$ -	$ 10
Derivative instruments, liabilities				
Foreign currency	$ -	$ 4	$ -	$ 4
Derivative instruments, liabilities	$ -	$ 4	$ -	$ 4

Interest rate swaps are measured at fair value with a market approach using actionable broker quotes which are Level 2 inputs. Foreign currency forwards are measured at fair value with a market approach using third-party pricing services, such as Bloomberg L.P., which have been corroborated with data from active markets for similar assets or liabilities, and are Level 2 inputs.

Fair values - Nonrecurring

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2014		2013		2012	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 43	$ 132	$ 5	$ 96	$ 16	$ 371

The substantial decline in commodity prices during the second half of 2014, and the resulting change in future commodity price assumptions, was a triggering event which required us to reassess long-lived assets related to oil and gas producing properties for impairment as of December 31, 2014. We estimated the fair values using an income approach and concluded that no material impairments were required. A period of sustained reduced commodity prices could result in non-cash impairment charges related to long-lived assets in future periods.

North America E&P

Long-lived assets held for use - Fair values are measured using an income approach based upon internal estimates of future production levels, prices and discount rate, all of which are Level 3 inputs. Inputs to the fair value measurement include reserve and production estimates made by our reservoir engineers, estimated future commodity prices adjusted for quality and location differentials, and forecasted operating expenses for the remaining estimated life of the reservoir.

In the third quarter of 2014, impairments of $53 million were recorded to Gulf of Mexico properties as a result of estimated abandonment cost and other revisions, to an aggregate fair value of $19 million. In addition, two fields were impaired a total of $47 million to an aggregate fair value of $24 million primarily due to lower forecasted commodity prices.

In the fourth quarter of 2012, declining natural gas prices related to our Powder River Basin asset prompted lower production expectations and reductions in estimated reserves which resulted in an impairment of $73 million. Subsequently, in the first quarter of 2013, as a result of our decision to wind down operations in the Powder River Basin due to poor economics, an additional impairment of $15 million was recorded to write down the assets' remaining value.

During 2012, the Ozona development, offshore Gulf of Mexico, produced toward abandonment pressures, and downward revisions of reserves were taken for an aggregate impairment of $289 million. Ozona production ceased in the first quarter of 2013 and an additional $21 million impairment was recorded. During 2014, we recorded additional impairments of $30 million at Ozona as a result of estimated abandonment cost revisions.

Other impairments of long-lived assets held for use in 2014, 2013 and 2012 were a result of reduced drilling expectations, reductions of estimated reserves or decreased commodity prices.

International E&P

Long-lived assets held for use - In the fourth quarter of 2013, as a result of E.G.'s natural gas policy related to the country's resources, we elected to cease our efforts to develop a second LNG production train on Bioko Island and recorded a $40 million impairment of all capitalized costs associated with engineering and feasibility studies. In addition, our share of income from EGHoldings included a $4 million impairment related to the same project, reflected in income from equity method investments in the 2013 consolidated statement of income.

Fair values - Financial instruments

Our current assets and liabilities include financial instruments, the most significant of which are receivables, commercial paper and payables. We believe the carrying values of our receivables, commercial paper and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our investment-grade credit rating, and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding receivables, commercial paper, payables and derivative financial instruments, and their reported fair value by individual balance sheet line item at December 31, 2014 and 2013.

	December 31,			
	2014		2013	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Other noncurrent assets	$ 132	$ 129	$ 154	$ 147
Total financial assets	$ 132	$ 129	$ 154	$ 147
Financial liabilities				
Other current liabilities	$ 13	$ 13	$ 13	$ 13
Long-term debt, including current portion[(a)]	6,887	6,360	6,922	6,427
Deferred credits and other liabilities	69	68	149	147
Total financial liabilities	$ 6,969	$ 6,441	$ 7,084	$ 6,587

[(a)] Excludes capital leases.

Fair values of our financial assets included in other noncurrent assets, and of our financial liabilities included in other current liabilities and deferred credits and other liabilities, are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

Most of our long-term debt instruments are publicly-traded. A market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value of such debt. The fair value of our debt that is not publicly-traded is measured using an income approach. The future debt service payments are discounted using the rate at which we currently expect to borrow. All inputs to this calculation are Level 3.

15. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 14. See Note 1 for discussion of the types of derivatives we use and the reasons for them. All of our interest rate and commodity derivatives are subject to enforceable master netting arrangements or similar agreements under which we may report net amounts. Netting is assessed by counterparty, and as of December 31, 2014 and 2013, there were no offsetting amounts. Positions by contract were all either assets or liabilities. The following tables present the gross fair values of derivative instruments, excluding cash collateral, and the reported net amounts along with where they appear on the consolidated balance sheets as of December 31, 2014 and 2013.

	December 31, 2014			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges			-	
Interest rate	$ 8	$ -	$ 8	Other noncurrent assets
Total Designated Hedges	$ 8	$ -	$ 8	

	December 31, 2013			
(In millions)	Asset	Liability	**Net Asset**	Balance Sheet Location
Fair Value Hedges				
Interest rate	$ 8	$ -	$ 8	Other noncurrent assets
Foreign currency	2	-	2	Other current assets
Total Designated Hedges	$ 10	$ -	$ 10	

	December 31, 2013			
(In millions)	Asset	Liability	**Net Liability**	Balance Sheet Location
Fair Value Hedges				
Foreign currency	$ -	$ 4	$ 4	Other current liabilities
Total Designated Hedges	$ -	$ 4	$ 4	

Derivatives Designated as Fair Value Hedges

The following table presents by maturity date, information about our interest rate swap agreements, including the weighted average, London Interbank Offer Rate ("LIBOR")-based, floating rate.

	December 31, 2014		December 31, 2013	
	Aggregate Notional Amount	Weighted Average, LIBOR-Based,	Aggregate Notional Amount	Weighted Average, LIBOR-Based,
Maturity Dates	(in millions)	Floating Rate	(in millions)	Floating Rate
October 2, 2017	$ 600	4.64%	$ 600	4.65%
March 15, 2018	$ 300	4.49%	$ 300	4.50%

As of December 31, 2013 our foreign currency forwards had an aggregate notional amount of 2,387 million Norwegian Kroner at a weighted average forward rate of 6.060. These forwards hedged the current Norwegian tax liability of the subsidiary that held our Norway business. There were none outstanding at December 31, 2014 as the open positions were transfered to the purchaser of our Norway business upon closing of the sale in the fourth quarter of 2014.

The pretax effect of derivative instruments designated as hedges of fair value in our consolidated statements of income is summarized in the table below. There is no ineffectiveness related to the fair value hedges.

		Gain (Loss)		
		Year Ended December 31,		
(In millions)	Income Statement Location	2014	2013	2012
Derivative				
Interest rate	Net interest and other	$ -	$ (13)	$ 16
Foreign currency	Discontinued operations	(36)	(44)	(1)
Hedged Item				
Long-term debt	Net interest and other	$ -	$ 13	$ (16)
Accrued taxes	Discontinued operations	36	44	1

Derivatives Not Designated as Hedges

In August 2012, we entered into crude oil derivative instruments related to a portion of our forecasted North America E&P crude oil sales. These commodity derivatives were not designated as hedges and expired in December 2013. We had no crude oil derivative instruments during 2014.

The impact of commodity derivative instruments not designated as hedges appears in sales and other operating revenues in our consolidated statements of income and was a net loss of $67 million in 2013 and a net gain of $70 million in 2012.

16. Debt

Short-term debt

As of December 31, 2014, we had no borrowings against our revolving credit facility, as described below, or under our U.S. commercial paper program that is backed by the revolving credit facility.

Long-term debt

In May 2014, we amended our $2.5 billion unsecured revolving credit facility (the "Credit Facility"), including an extension of the maturity to May 2019. Terms of this amended Credit Facility include the ability to request two one-year extensions, an option to increase the commitment amount by up to an additional $1.0 billion, subject to the consent of any increasing lenders, and sub-facilities for swing-line loans and letters of credit up to an aggregate amount of $100 million and $500 million. Fees on the unused commitment of each lender range from 8 basis points to 22.5 basis points depending on our credit ratings. Borrowings under the Credit Facility bear interest, at our option, at either (a) an adjusted LIBOR rate plus a margin ranging from 87.5 basis points to 150 basis points depending on our credit ratings or (b) the Base Rate plus a margin ranging from 0 basis points to 50 basis points depending on our credit ratings. Base Rate is defined as a per annum rate equal to the greatest of (a) the prime rate, (b) the federal funds rate plus one-half of one percent or (c) LIBOR for a one-month interest period plus 1 percent.

The Credit Facility contains a covenant that requires our ratio of total debt to total capitalization not to exceed 65 percent as of the last day of each fiscal quarter. If an event of default occurs, the lenders holding more than half of the commitments may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings

and the cash collateralization of all outstanding letters of credit under the Credit Facility. We are in compliance with this covenant as of December 31, 2014.

The following table details our long-term debt:

	December 31,	
(In millions)	2014	2013
Senior unsecured notes:		
0.900% notes due 2015[a]	$ 1,000	$ 1,000
6.000% notes due 2017[a]	682	682
5.900% notes due 2018[a]	854	854
7.500% notes due 2019[a]	228	228
2.800% notes due 2022[a]	1,000	1,000
9.375% notes due 2022	32	32
Series A notes due 2022	3	3
8.500% notes due 2023	70	70
8.125% notes due 2023	131	131
6.800% notes due 2032[a]	550	550
6.600% notes due 2037	750	750
Capital leases:		
Capital lease obligation of consolidated subsidiary due 2015 - 2049	9	10
Other obligations:		
4.550% promissory note, semi-annual payments due 2015	68	136
5.125% obligation relating to revenue bonds due 2037	1,000	1,000
Total[b]	6,377	6,446
Unamortized discount	(8)	(9)
Fair value adjustments[c]	22	25
Amounts due within one year	(1,068)	(68)
Total long-term debt	$ 5,323	$ 6,394

(a) These notes contain a make-whole provision allowing us to repay the debt at a premium to market price.
(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $236 million at December 31, 2014 may be declared immediately due and payable.
(c) See Notes 14 and 15 for information on interest rate swaps.

The following table shows future long-term debt payments:

(In millions)	
2015	$ 1,068
2016	-
2017	682
2018	854
2019	228
Thereafter	3,545
Total long-term debt, including current portion	$ 6,377

17. Asset Retirement Obligations

The following summarizes the changes in asset retirement obligations:

(In millions)	2014	2013
Beginning balance	$ 2,096	$ 1,783
Incurred, including acquisitions	89	84
Settled, including dispositions[(a)]	(426)	(78)
Accretion expense (included in depreciation, depletion and amortization)	104	106
Revisions to previous estimates	95	244
Held for sale	-	(43)
Ending balance[(b)]	$ 1,958	$ 2,096

(a) Includes the sale of our Norway business in the fourth quarter of 2014.
(b) Includes asset retirement obligations of $41 million and $87 million classified as short-term at December 31, 2014 and 2013.

18. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	2014	2013	2012
Net cash provided by operating activities:			
Interest paid (net of amounts capitalized)	$ 289	307	$ 225
Income taxes paid to taxing authorities [(a)]	1,679	3,904	4,974
Commercial paper, net:			
Issuances	$ 2,345	$ 10,870	$ 13,880
Repayments	(2,480)	(10,935)	(13,680)
Commercial paper, net	$ (135)	$ (65)	$ 200
Noncash investing activities, related to continuing operations:			
Asset retirement costs capitalized	151	290	199
Change in capital expenditure accrual	335	6	165
Liabilities assumed in acquisitions	-	-	109
Asset retirement obligations assumed by buyer	359	92	8
Debt payments made by United States Steel	-	-	20

(a) Income taxes paid to taxing authorities includes $1,312 million, $2,270 million and $2,336 million in 2014, 2013, and 2012 related to discontinued operations.

19. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees as well as international employees located in the U.K. Benefits under these plans are based on plan provisions specific to each plan.

We also have defined benefit plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Life insurance benefits are provided to certain retiree beneficiaries. Other postretirement benefits are not funded in advance.

Obligations and funded status - The accumulated benefit obligation for all defined benefit pension plans was $1,403 million and $1,359 million as of December 31, 2014 and 2013.

As of December 31, 2014 and 2013, our U.S. plans had accumulated benefit obligations in excess of plan assets. Summary information for these defined benefit pension plans follows.

	December 31,	
(In millions)	2014	2013
Projected benefit obligation	$ (894)	$ (933)
Accumulated benefit obligation	(793)	(791)
Fair value of plan assets	574	625

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The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits											
	2014				2013				Other Benefits			
(In millions)	U.S.		Int'l		U.S.		Int'l		2014		2013	
Change in benefit obligations:												
Beginning balance	$	933	$	649	$	1,146	$	565	$	279	$	311
Service cost		31		16		33		22		3		4
Interest cost		35		27		40		24		13		12
Plan amendment[a]		-		-		-		-		(42)		-
Actuarial loss (gain)[b]		174		46		(140)		40		42		(31)
Foreign currency exchange rate changes		-		(39)		-		11		-		-
Divestiture[c]		-		(29)		-		-		-		-
Benefits paid		(279)		(19)		(146)		(13)		(16)		(17)
Ending balance	$	894	$	651	$	933	$	649	$	279	$	279
Change in fair value of plan assets:												
Beginning balance	$	625	$	597	$	630	$	500	$	-	$	-
Actual return on plan assets		59		59		65		74		-		-
Employer contributions		169		37		76		23		-		-
Foreign currency exchange rate changes		-		(39)		-		13		-		-
Divestiture[c]		-		(13)		-		-		-		-
Benefits paid		(279)		(19)		(146)		(13)		-		-
Ending balance	$	574	$	622	$	625	$	597	$	-	$	-
Funded status of plans at December 31	$	(320)	$	(29)	$	(308)	$	(52)	$	(279)	$	(279)
Amounts recognized in the consolidated balance sheets:												
Current liabilities		(11)		-		(16)		-		(19)		(19)
Noncurrent liabilities		(309)		(29)		(292)		(52)		(260)		(260)
Accrued benefit cost	$	(320)	$	(29)	$	(308)	$	(52)	$	(279)	$	(279)
Pretax amounts in accumulated other comprehensive loss:												
Net loss (gain)	$	283	$	91	$	262	$	59	$	34	$	(8)
Prior service cost (credit)		10		8		15		9		(41)		(5)

[a] Represents a change in plan design related to the health care benefits provided under the postretirement plan.
[b] Includes the increase in the U.S. pension and postretirement benefit obligations of $13 million and $15 million respectively, due to the adoption of the 2014 mortality table.
[c] Related to the sale of our Norway business in the fourth quarter of 2014.

Components of net periodic benefit cost from continuing operations and other comprehensive (income) loss - The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

	Pension Benefits								
	Year Ended December 31,						Other Benefits		
	2014		2013		2012		Year Ended December 31,		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2014	2013	2012
Components of net periodic benefit cost:									
Service cost	$ 31	$ 16	$ 33	$ 17	$ 31	$ 15	$ 3	$ 4	$ 4
Interest cost	35	27	40	23	42	22	13	12	14
Expected return on plan assets	(34)	(32)	(43)	(24)	(43)	(23)	-	-	-
Amortization:									
- prior service cost (credit)	5	1	6	1	7	1	(6)	(6)	(7)
- actuarial loss	29	1	43	4	48	4	-	-	-
Net settlement loss[(a)]	99	-	45	-	45	-	-	-	-
Net periodic benefit cost[(b)]	$ 165	$ 13	$ 124	$ 21	$ 130	$ 19	$ 10	$ 10	$ 11
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)[(c)]	$ 149	$ 33	$ (161)	$ (15)	$ 172	$ 14	$ 42	$ (31)	$ 7
Amortization of actuarial (loss) gain	(128)	(1)	(88)	(4)	(93)	(4)	-	-	-
Prior service cost (credit)	-	-	-	-	-	1	(42)	-	-
Amortization of prior service credit (cost)	(5)	(1)	(6)	(1)	(7)	(1)	6	6	7
Total recognized in other comprehensive (income) loss	$ 16	$ 31	$ (255)	$ (20)	$ 72	$ 10	$ 6	$ (25)	$ 14
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 181	$ 44	$ (131)	$ 1	$ 202	$ 29	$ 16	$ (15)	$ 25

(a) Settlement losses are recorded when lump sum payments from a plan in a period exceed the plan's total service and interest costs for the period. Such settlements occurred in one or more of our U.S. pension plans in all periods presented.
(b) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.
(c) Includes the impact of the sale of our Norway business in the fourth quarter of 2014.

The estimated net loss and prior service cost for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $27 million and $6 million. The estimated net loss and prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $1 million and $4 million.

Plan assumptions - The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2014, 2013 and 2012.

	Pension Benefits								
	2014		2013		2012		Other Benefits		
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	2014	2013	2012
Weighted average assumptions used to determine benefit obligation:									
Discount rate	3.71%	3.70%	4.28%	4.60%	3.44%	4.40%	4.01%	4.85%	4.06%
Rate of compensation increase	4.00%	3.60%	5.00%	4.90%	5.00%	4.50%	4.00%	5.00%	5.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	3.98%	4.60%	3.79%	4.40%	4.21%	4.70%	4.69%	4.06%	4.90%
Expected long-term return on plan assets	6.75%	5.70%	7.25%	4.90%	7.75%	5.20%	-	-	-
Rate of compensation increase	5.00%	4.90%	5.00%	4.50%	5.00%	4.30%	5.00%	5.00%	5.00%

Expected long-term return on plan assets

U.S. plan - The expected long-term return on plan assets assumption for our U.S. funded plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group. The tool utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation to derive an expected long-term rate of return on those assets.

International plans - To determine the expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation in our international pension plans to develop the overall expected long-term return on plan assets assumption.

Assumed weighted average health care cost trend rates

	2014	2013	2012
Initial health care trend rate	6.88%	6.89%	7.24%
Ultimate trend rate	5.00%	5.00%	5.00%
Year ultimate trend rate is reached	2024	2020	2019

Prior to a recent plan amendment, the assumed health care cost trend rates had a significant effect on the amounts reported for our defined benefit retiree health care plans. After the plan amendment, the employer provided subsidy for post-65 retiree health care coverage will only increase by the consumer price index (not to exceed 4 percent) each year. Company contributions would be funded to a Health Reimbursement Account on the retiree's behalf to subsidize the retiree's cost of obtaining health care benefits through a private exchange. Therefore, a one-percentage-point change in health care cost trend rates would not have a material impact on either the service and interest cost components and the postretirement benefit obligations.

Plan investment policies and strategies - The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with the legal requirements of all applicable laws; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plan's investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation.

U.S. plan - The plan's current targeted asset allocation is comprised of 55 percent equity securities and 45 percent other fixed income securities. Over time, as the plan's funded ratio (as defined by the investment policy) improves, in order to reduce volatility in returns and to better match the plan's liabilities, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. The plan's assets are managed by a third-party investment manager. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

International plan - Our international plan's target asset allocation is comprised of 62.5 percent equity securities and 37.5 percent fixed income securities. The plan assets are invested in eight separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers. The investment managers' performance is measured independently by a third-party asset servicing consulting firm. Overall, investment performance and risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and periodic asset and liability studies.

Fair value measurements - Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2014 and 2013.

Cash and cash equivalents - Cash and cash equivalents are valued using a market approach and are considered Level 1. This investment also includes a cash reserve account (a collective short-term investment fund) that is valued using an income approach and is considered Level 2.

Equity securities - Investments in common stock, preferred stock, and real estate investment trusts ("REIT") are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership. These private equity investments are considered Level 3.

Mutual funds - Investments in mutual funds are valued using a market approach. The shares or units held are traded on the public exchanges and are therefore considered Level 1.

Pooled funds - Investments in pooled funds are valued using a market approach at the net asset value ("NAV") of units held. The various funds consist of either an equity or fixed income investment portfolio with underlying investments held in U.S. and non-U.S. securities. Nearly all of the underlying investments are publicly-traded. The majority of the pooled funds are benchmarked against a relative public index. These are considered Level 2.

Fixed income securities - Fixed income securities are valued using a market approach. U.S. treasury notes and exchange traded funds ("ETFs") are valued at the closing price reported in an active market, and are considered Level 1. Corporate bonds and other bonds are valued using calculated yield curves created by models that incorporate various market factors and are considered Level 2. The investment in the commingled fund is valued using the NAV of units held, and is considered Level 2. The commingled fund consists of an equity and fixed income portfolio with underlying investments held in U.S. and non-U.S. securities.

Other - Other investments are composed of an international insurance carrier contract and the majority of the underlying investments consist of a mix of non-U.S. publicly traded equity securities valued at the closing price reported in an active market and fixed income securities valued using calculated yield curves. This asset is considered Level 2. The other investments, an unallocated annuity contract, two limited liability companies and real estate are considered Level 3, as inputs to determine fair value are unobservable and significant to the overall fair value measurement.

The following tables present the fair values of our defined benefit pension plan's assets, by level within the fair value hierarchy, as of December 31, 2014 and 2013.

	December 31, 2014							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 26	$ 1	$ -	$ -	$ -	$ -	$ 26	$ 1
Equity securities:								
Common and preferred stock[a]	230	-	-	-	-	-	230	-
Private equity	-	-	-	-	25	-	25	-
Mutual and pooled funds[b]	-	221	-	164	-	-	-	385
Fixed income securities:								
U.S. treasury notes and ETFs	33	-	-	-	-	-	33	-
Corporate and other bonds[c]	-	-	190	-	-	-	190	-
Commingled and pooled funds[d]	-	-	40	236	-	-	40	236
Other	-	-	-	-	30	-	30	-
Total investments, at fair value	$ 289	$ 222	$ 230	$ 400	$ 55	$ -	$ 574	$ 622

	December 31, 2013							
(In millions)	Level 1		Level 2		Level 3		Total	
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l
Cash and cash equivalents	$ 19	$ 1	$ 1	$ -	$ -	$ -	$ 20	$ 1
Equity securities:								
Common and preferred stock[a]	292	-	-	-	-	-	292	-
REIT and private equity	2	-	-	-	23	-	25	-
Mutual and pooled funds[b]	-	219	-	186	-	-	-	405
Fixed income securities:							-	-
U.S. treasury notes and ETFs	65	-	-	-	-	-	65	-
Corporate and other bonds[c]	-	-	172	-	-	-	172	-
Commingled and pooled funds[d]	-	-	17	178	-	-	17	178
Other	-	-	-	13	34	-	34	13
Total investments, at fair value	$ 378	$ 220	$ 190	$ 377	$ 57	$ -	$ 625	$ 597

[a] Primarily investments held in U.S. and non-U.S. common stocks in diverse industries.
[b] Mutual funds - Primarily investments held in U.S. and non-U.S. common stocks in diverse industries.
Pooled funds - Primarily investments held in non-U.S. publicly traded common stocks in diverse industries.
[c] Corporate bonds - Primarily investments held in U.S. and non-U.S. corporate bonds in diverse industries.
Other bonds - Primarily consist of securities issued by governmental agencies and municipalities.
[d] Pooled funds - Primarily investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds.

The activity during the year ended December 31, 2014 and 2013, for the assets using Level 3 fair value measurements was immaterial.

Cash flows

Estimated future benefit payments - The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2014 and reflect expected future services, as appropriate, are to be paid in the years indicated.

	Pension Benefits		Other
(In millions)	U.S.	Int'l	Benefits
2015	$ 80	$ 15	$ 19
2016	78	17	19
2017	83	19	19
2018	79	22	19
2019	74	23	19
2020 through 2024	299	128	93

Contributions to defined benefit plans - We expect to make contributions to the funded pension plans of up to $95 million in 2015. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $11 million and $19 million in 2015.

Contributions to defined contribution plan - We contribute to a defined contribution plan for eligible employees. Contributions to this plan totaled $24 million, $26 million and $25 million in 2014, 2013 and 2012.

20. Incentive Based Compensation

Description of stock-based compensation plans - The Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") was approved by our stockholders in April 2012 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance awards to employees. The 2012 Plan also allows us to provide equity compensation to our non-employee directors. No more than 50 million shares of our common stock may be issued under the 2012 Plan. For stock options and SARs, the number of shares available for issuance under the 2012 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For stock awards (including restricted stock and restricted stock unit awards), the number of shares available for issuance under the 2012 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2012 Plan that are forfeited, are terminated or expire unexercised become available for future grants. In addition, the number of shares of our common stock reserved for issuance under the 2012 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2012 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2012 Plan, no new grants were or will be made from the 2007 Incentive Compensation Plan, the 2003 Incentive Compensation Plan (the "2003 Plan"), the Non-Employee Director Stock Plan or the deferred stock benefit provision of the Deferred Compensation Plan for Non-Employee Directors (collectively, the "Prior Plans"). Any awards previously granted under the Prior Plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock-based awards under the plans

Stock options - We grant stock options under the 2012 Plan and we previously granted stock options under certain of the Prior Plans. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. In general, our stock options vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

Prior to 2005, we granted SARs under the 2003 Plan. No SARs have been granted since then and at December 31, 2014 there are no additional SARs outstanding. SARs represent the right to receive shares of common stock equal in value to the excess of the fair market value of shares of common stock on the date the right is exercised over the grant price. In general, SARs vested ratably over a three-year period and have a maximum term of ten years from the date they were granted.

Restricted stock - We grant restricted stock and restricted stock units (collectively, "restricted stock awards") under the 2012 Plan and we previously granted such awards under certain of the Prior Plans. The restricted stock awards granted to

officers generally vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees and restricted stock units to certain international employees, based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest ratably over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares are not transferable and are held by our transfer agent.

Stock-based performance units - Beginning in 2013, we grant stock-based performance units to officers under the 2012 Plan. At the grant date, each unit represents the value of one share of our common stock. These units provide a cash payout, based on the value of anywhere from zero to two times the number of units granted, upon the achievement of certain performance goals at the end of a 36-month performance period. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. Dividend equivalents accrue during the performance period and are paid in cash at the end of the performance period based on the number of shares that would represent the value of the units.

Common stock units - We maintain an equity compensation program for our non-employee directors under the 2012 Plan and previously maintained such a program under certain of the Prior Plans. All non-employee directors receive annual grants of common stock units. Common shares will be issued for units granted on or after January 1, 2012 upon completion of board service or three years from the date of grant, whichever is earlier. Those units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. When dividends are paid on our common stock, directors receive dividend equivalents in the form of additional common stock units.

Total stock-based compensation expense - Total employee stock-based compensation expense was $70 million, $70 million and $67 million in 2014, 2013 and 2012, while the total related income tax benefits were $25 million, $25 million and $24 million in the same years. In 2014, 2013 and 2012, cash received upon exercise of stock option awards was $136 million, $58 million and $41 million. Tax benefits realized for deductions for stock awards exercised during 2014, 2013 and 2012 totaled $51 million, $36 million and $24 million.

Stock option awards - During 2014, 2013 and 2012, we granted stock option awards to both officer and non-officer employees. The weighted average grant date fair value of these awards was based on the following weighted average Black-Scholes assumptions:

	2014	2013	2012
Exercise price per share	$34.49	$33.54	$33.52
Expected annual dividend yield	2.3%	2.1%	2.2%
Expected life in years	5.9	6.1	5.5
Expected volatility	38%	38%	41%
Risk-free interest rate	1.8%	1.6%	1.2%
Weighted average grant date fair value of stock option awards granted	$10.50	$10.25	$10.86

The following is a summary of stock option award activity in 2014.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Average Intrinsic Value *(in millions)*
Outstanding at beginning of year	18,104,887	$27.27		
Granted	1,935,895	$34.49		
Exercised	(5,959,647)	$23.43		
Canceled	(653,299)	$34.05		
Outstanding at end of year	13,427,836	$29.68	5 years	$ 39
Exercisable at end of year	10,435,751	$28.39	4 years	$ 39
Expected to vest	2,914,069	$34.18	8 years	$ -

The intrinsic value of stock option awards exercised during 2014, 2013 and 2012, was $83 million, $35 million and $40 million.

As of December 31, 2014, unrecognized compensation cost related to stock option awards was $18 million, which is expected to be recognized over a weighted average period of two years.

Restricted stock awards - The following is a summary of restricted stock award activity in 2014.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	4,031,888	$31.80
Granted	1,970,880	$34.98
Vested	(1,845,327)	$30.64
Forfeited	(709,088)	$32.73
Unvested at end of year	3,448,353	$34.04

The vesting date fair value of restricted stock awards which vested during 2014, 2013 and 2012 was $70 million, $59 million and $36 million. The weighted average grant date fair value of restricted stock awards was $34.04, $31.80, and $29.02 for awards unvested at December 31, 2014, 2013 and 2012.

As of December 31, 2014 there was $82 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of two years.

Stock-based performance unit awards - During 2014 and 2013, we granted 221,491 and 353,600 stock-based performance unit awards to officers. At December 31, 2014, there were 276,331 units outstanding.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2014 and 2013 were:

	2014	2013
Valuation date stock price	$28.29	$28.29
Expected annual dividend yield	2.9%	2.9%
Expected volatility	26%	27%
Risk-free interest rate	0.7%	0.3%
Fair value of stock-based performance units outstanding	$25.06	$21.06

Cash-based performance unit awards - Prior to 2013, cash-based performance unit awards were granted to officers that provide a cash payment upon the achievement of certain performance goals at the end of a defined measurement period. The performance goals are tied to our TSR as compared to TSR for a group of peer companies determined by the Compensation Committee of the Board of Directors. The target value of each performance unit is $1, with a maximum payout of $2 per unit, but the actual payout could be anywhere between zero and the maximum. Because performance units are to be settled in cash at the end of the performance period, they are accounted for as liability awards.

During 2012, we granted 12.7 million performance units, all having a 36-month performance period. During the third quarter of 2011, we granted 15 million performance units, a portion of which had a 30-month performance period and a portion of which had an 18-month performance period to reflect the remaining periods of the original 2011 and 2010 performance unit grants outstanding prior to the spin-off. Compensation expense associated with cash-based performance units was $5 million, $9 million and $12 million, in 2014, 2013 and 2012. At December 31, 2014 all performance periods have ended and no additional units will be granted.

21. Reclassifications Out of Accumulated Other Comprehensive Loss

The following table presents a summary of amounts reclassified from accumulated other comprehensive loss to income from continuing operations in their entirety:

	Year Ended December 31,		
(In millions)	2014	2013	Income Statement Line
Accumulated Other Comprehensive Loss Components			
	Income (Expense)		
Postretirement and postemployment plans			
Amortization of actuarial loss	$ (30)	$ (47)	General and administrative
Net settlement loss	(99)	(45)	General and administrative
	(129)	(92)	Income from operations
	62	34	Provision for income taxes
Other insignificant items, net of tax	(1)	(1)	
Total reclassifications for the period	$ (68)	$ (59)	Income from continuing operations

22. Stockholders' Equity

In 2014 we acquired 29 million common shares at a cost of $1 billion under our share repurchase program, initially authorized in 2006, bringing our total repurchases to 121 million common shares at a cost of $4.7 billion. As of December 31, 2014 the total remaining share repurchase authorization was $1.5 billion. Purchases under the program may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables.

23. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for capital lease obligations and for operating lease obligations having noncancellable lease terms in excess of one year are as follows:

(In millions)	Capital Lease Obligations	Operating Lease Obligations
2015	$ 1	$ 40
2016	1	33
2017	1	26
2018	1	24
2019	1	24
Later years	19	32
Sublease rentals	-	(3)
Total minimum lease payments	$ 24	$ 176
Less imputed interest costs	(15)	
Present value of net minimum lease payments	$ 9	

Operating lease rental expense related to continuing operations was $120 million, $105 million and $98 million in 2014, 2013 and 2012.

24. Commitments and Contingencies

We are a defendant in a number of lawsuits arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Environmental matters - We are subject to federal, state, local and foreign laws and regulations relating to the environment. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2014 and 2013, accrued liabilities for remediation were not significant. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees - We have entered into a guarantee of a long-term transportation services agreement and a performance guarantee related to asset retirement obligations with aggregate maximum potential undiscounted payments totaling $57 million as of December 31, 2014. Under the terms of these guarantee arrangements, we would be required to perform should the guaranteed party fail to fulfill its obligations under the specified arrangements.

Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

***Contract commitments* -** At December 31, 2014 and 2013, contractual commitments to acquire property, plant and equipment totaled $747 million and $1,270 million.

***Other contingencies* -** During the second quarter of 2011, the AOSP operator determined the need and developed preliminary plans to address water flow into a previously mined and contained section of the Muskeg River mine. At December 31, 2014, the remaining liability is $24 million.

Select Quarterly Financial Data (Unaudited)

	2014				2013			
(In millions, except per share data)	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues	$ 2,690	$ 2,888	$ 2,870	$ 2,398	$ 2,880	$ 3,010	$ 3,000	$ 2,435
Income (loss) from continuing operations before income taxes	598	511	453	(201)	608	804	755	226
Income (loss) from continuing operations	398	360	304	(93)	158	241	396	136
Discontinued operations [a]	751	180	127	1,019	225	185	173	239
Net income	$ 1,149	$ 540	$ 431	$ 926	$ 383	$ 426	$ 569	$ 375
Income (loss) per share:								
Basic:								
Continuing operations	$0.58	$0.53	$0.45	$(0.14)	$0.22	$0.34	$0.56	$0.20
Discontinued operations [a]	$1.08	$0.27	$0.19	$1.51	$0.32	$0.26	$0.24	$0.34
Net income	$1.66	$0.80	$0.64	$1.37	$0.54	$0.60	$0.80	$0.54
Diluted:								
Continuing operations	$0.57	$0.53	$0.45	($0.14)	$0.22	$0.34	$0.56	$0.20
Discontinued operations [a]	$1.08	$0.27	$0.19	$1.51	$0.32	$0.26	$0.24	$0.34
Net income	$1.65	$0.80	$0.64	$1.37	$0.54	$0.60	$0.80	$0.54
Dividends paid per share	$0.19	$0.19	$0.21	$0.21	$0.17	$0.17	$0.19	$0.19

We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014. The Angola assets and Norway business are reflected as discontinued operations in all periods presented.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; Canada; E.G.; Other Africa, which primarily includes activities in Gabon, Kenya, Ethiopia and Libya; and Other International ("Other Int'l"), which includes the U.K. and the Kurdistan Region of Iraq. We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014, and both are shown as discontinued operations ("Disc Ops") in all periods.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of crude oil and condensate, natural gas liquids, natural gas and synthetic crude oil is a highly technical process which is based upon several underlying assumptions that are subject to change. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity - Critical Accounting Estimates - Estimated Quantities of Net Reserves. For a discussion of our reserve estimation process, including the use of third-party audits, see Item 1. Business - Reserves.

Our December 31, 2014 proved reserves were calculated using the unweighted average of closing prices for the first day of each month in 2014 within the 12-month period. The 2014 unweighted averages for certain of the benchmark prices were as follows:

- WTI crude oil - $94.99 per bbl
- Henry Hub natural gas - $4.31 per mmbtu
- Brent crude oil - $101.39 per bbl

When determining the December 31, 2014 proved reserves for each property, the benchmark prices listed above were adjusted with price differentials that account for property-specific quality and location differences. Beginning in the second half of 2014, the crude oil benchmarks began to decline and this decline continued into early 2015. In addition, the Henry Hub natural gas benchmark began to decline in late 2014 and continued its decline into 2015. Commodity prices are likely to remain volatile based on global supply and demand and could decline further. The January 2015 benchmark closing prices for the first day of the month were WTI crude oil of $52.69 per bbl, Henry Hub natural gas of $2.99 per mmbtu and Brent crude oil of $55.55 per bbl. Sustained reduced commodity prices could have a material effect on the quantity and future cash flows of our proved reserves. To the extent that we experience a sustained period of reduced commodity prices in 2015, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing the reserves as of the end of the year. The decline in commodity prices experienced in the second half of 2014 has resulted in a reduction in the costs of developing and producing reserves. The impact of sustained reduced commodity prices on future cash flows will be partially offset by the impact of lower costs.

A sustained period of lower commodity prices could also cause us to decrease our near term capital programs and defer investment until prices improve. A shifting of capital expenditures into future periods outside of five years from the initial proved reserve booking could potentially lead to a reduction in proved undeveloped reserves. See Item 1A. Risk Factors for a further discussion of how a substantial extended decline in commodity prices could impact us.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Crude oil and condensate								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	236	-	77	222	25	560	89	649
Revisions of previous estimates	7	-	4	(5)	5	11	23	34
Improved recovery	2	-	-	-	-	2	-	2
Purchases of reserves in place	37	-	-	-	-	37	-	37
Extensions, discoveries and other additions	140	-	-	7	-	147	-	147
Production	(35)	-	(9)	(15)	(6)	(65)	(30)	(95)
End of year - 2012	387	-	72	209	24	692	82	774
Revisions of previous estimates	33	-	(1)	12	6	50	19	69
Improved recovery	-	-	-	-	-	-	11	11
Purchases of reserves in place	12	-	-	-	-	12	-	12
Extensions, discoveries and other additions	112	-	1	3	-	116	8	124
Production	(46)	-	(8)	(9)	(5)	(68)	(29)	(97)
Sales of reserves in place	(1)	-	-	-	-	(1)	-	(1)
End of year - 2013	497	-	64	215	25	801	91	892
Revisions of previous estimates	36	-	(1)	(4)	1	32	10	42
Improved recovery	2	-	-	-	-	2	-	2
Purchases of reserves in place	6	-	-	-	-	6	-	6
Extensions, discoveries and other additions	153	-	1	-	7	161	3	164
Production	(57)	-	(7)	(3)	(4)	(71)	(17)	(88)
Sales of reserves in place	(3)	-	-	-	-	(3)	(87)	(90)
End of year - 2014	634	-	57	208	29	928	-	928
Proved developed reserves:								
Beginning of year - 2012	128	-	52	179	20	379	64	443
End of year - 2012	169	-	45	168	20	402	63	465
End of year - 2013	241	-	37	176	19	473	77	550
End of year - 2014	294	-	30	175	19	518	-	518
Proved undeveloped reserves:								
Beginning of year - 2012	108	-	25	43	5	181	25	206
End of year - 2012	218	-	27	41	4	290	19	309
End of year - 2013	256	-	27	39	6	328	14	342
End of year - 2014	340	-	27	33	10	410	-	410

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas liquids								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	43	-	40	-	1	84	-	84
Revisions of previous estimates	2	-	2	-	-	4	-	4
Purchases of reserves in place	15	-	-	-	-	15	-	15
Extensions, discoveries and								
other additions	32	-	-	-	-	32	-	32
Production	(4)	-	(4)	-	-	(8)	-	(8)
End of year - 2012	88	-	38	-	1	127	-	127
Revisions of previous estimates	13	-	-	-	-	13	-	13
Purchases of reserves in place	2	-	-	-	-	2	-	2
Extensions, discoveries and								
other additions	25	-	-	-	-	25	-	25
Production	(9)	-	(4)	-	-	(13)	-	(13)
End of year - 2013	119	-	34	-	1	154	-	154
Revisions of previous estimates	4	-	-	-	-	4	-	4
Purchases of reserves in place	1	-	-	-	-	1	-	1
Extensions, discoveries and								
other additions	48	-	-	-	-	48	-	48
Production	(11)	-	(4)	-	-	(15)	-	(15)
Sales of reserves in place	-	-	-	-	-	-	-	-
End of year - 2014	161	-	30	-	1	192	-	192
Proved developed reserves:								
Beginning of year - 2012	13	-	26	-	-	39	-	39
End of year - 2012	29	-	23	-	1	53	-	53
End of year - 2013	51	-	18	-	1	70	-	70
End of year - 2014	68	-	15	-	-	83	-	83
Proved undeveloped reserves:								
Beginning of year - 2012	30	-	14	-	1	45	-	45
End of year - 2012	59	-	15	-	-	74	-	74
End of year - 2013	68	-	16	-	-	84	-	84
End of year - 2014	93	-	15	-	1	109	-	109

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	872	-	1,571	104	21	2,568	98	2,666
Revisions of previous estimates	(29)	-	10	(1)	5	(15)	10	(5)
Purchases of reserves in place	105	-	-	-	-	105	-	105
Extensions, discoveries and								
other additions	224	-	-	111	-	335	-	335
Production[(b)]	(129)	-	(157)	(5)	(12)	(303)	(19)	(322)
End of year - 2012	1,043	-	1,424	209	14	2,690	89	2,779
Revisions of previous estimates	(4)	-	45	4	23	68	20	88
Purchases of reserves in place	13	-	3	-	-	16	-	16
Extensions, discoveries and								
other additions	163	-	9	-	-	172	3	175
Production[(b)]	(114)	-	(161)	(8)	(9)	(292)	(19)	(311)
Sales of reserves in place	(76)	-	-	-	-	(76)	-	(76)
End of year - 2013	1,025	-	1,320	205	28	2,578	93	2,671
Revisions of previous estimates	(24)	-	1	5	2	(16)	7	(9)
Purchases of reserves in place	5	-	-	-	-	5	-	5
Extensions, discoveries and								
other additions	290	-	44	-	-	334	2	336
Production[(b)]	(113)	-	(160)	(1)	(8)	(282)	(13)	(295)
Sales of reserves in place	(39)	-	-	-	-	(39)	(89)	(128)
End of year - 2014	1,144	-	1,205	209	22	2,580	-	2,580
Proved developed reserves:								
Beginning of year - 2012	551	-	1,104	104	16	1,775	24	1,799
End of year - 2012	546	-	980	99	8	1,633	20	1,653
End of year - 2013	540	-	823	95	21	1,479	20	1,499
End of year - 2014	575	-	664	94	17	1,350	-	1,350
Proved undeveloped reserves:								
Beginning of year - 2012	321	-	467	-	5	793	74	867
End of year - 2012	497	-	444	110	6	1,057	69	1,126
End of year - 2013	485	-	497	110	7	1,099	73	1,172
End of year - 2014	569	-	541	115	5	1,230	-	1,230

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Synthetic crude oil								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	-	623	-	-	-	623	-	623
Revisions of previous estimates	-	45	-	-	-	45	-	45
Production	-	(15)	-	-	-	(15)	-	(15)
End of year - 2012	-	653	-	-	-	653	-	653
Revisions of previous estimates	-	36	-	-	-	36	-	36
Extensions, discoveries and other additions	-	6	-	-	-	6	-	6
Production	-	(15)	-	-	-	(15)	-	(15)
End of year - 2013	-	680	-	-	-	680	-	680
Revisions of previous estimates	-	(55)	-	-	-	(55)	-	(55)
Purchases of reserves in place	-	38	-	-	-	38	-	38
Production	-	(15)	-	-	-	(15)	-	(15)
End of year - 2014	-	648	-	-	-	648	-	648
Proved developed reserves:								
Beginning of year - 2012	-	623	-	-	-	623	-	623
End of year - 2012	-	653	-	-	-	653	-	653
End of year - 2013	-	674	-	-	-	674	-	674
End of year - 2014	-	644	-	-	-	644	-	644
Proved undeveloped reserves:								
End of year - 2013	-	6	-	-	-	6	-	6
End of year - 2014	-	4	-	-	-	4	-	4

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	Canada	E.G.[(a)]	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Total Proved Reserves								
Proved developed and undeveloped reserves:								
Beginning of year - 2012	424	623	379	239	29	1,694	106	1,800
Revisions of previous estimates	5	45	7	(5)	6	58	24	82
Improved recovery	2	-	-	-	-	2	-	2
Purchases of reserves in place	70	-	-	-	-	70	-	70
Extensions, discoveries and other additions	209	-	-	26	-	235	-	235
Production[(b)]	(61)	(15)	(39)	(16)	(8)	(139)	(33)	(172)
End of year - 2012	649	653	347	244	27	1,920	97	2,017
Revisions of previous estimates	45	36	7	12	11	111	21	132
Improved recovery	-	-	-	-	-	-	11	11
Purchases of reserves in place	16	-	1	-	-	17	-	17
Extensions, discoveries and								-
other additions	164	6	2	3	-	175	9	184
Production[(b)]	(74)	(15)	(39)	(10)	(7)	(145)	(32)	(177)
Sales of reserves in place	(13)	-	-	-	-	(13)	-	(13)
End of year - 2013	787	680	318	249	31	2,065	106	2,171
Revisions of previous estimates	36	(55)	-	(3)	-	(22)	11	(11)
Improved recovery	2	-	-	-	-	2	-	2
Purchases of reserves in place	8	38	-	-	-	46	-	46
Extensions, discoveries and								-
other additions	250	-	8	-	7	265	3	268
Production[(b)]	(87)	(15)	(38)	(3)	(5)	(148)	(19)	(167)
Sales of reserves in place	(10)	-	-	-	-	(10)	(101)	(111)
End of year - 2014	986	648	288	243	33	2,198	-	2,198
Proved developed reserves:								
Beginning of year - 2012	233	623	262	196	23	1,337	68	1,405
End of year - 2012	289	653	231	185	22	1,380	66	1,446
End of year - 2013	382	674	193	192	23	1,464	80	1,544
End of year - 2014	458	644	155	191	22	1,470	-	1,470
Proved undeveloped reserves:								
Beginning of year - 2012	191	-	117	43	6	357	38	395
End of year - 2012	360	-	116	59	5	540	31	571
End of year - 2013	405	6	125	57	8	601	26	627
End of year - 2014	528	4	133	52	11	728	-	728

(a) Consists of estimated reserves from properties governed by production sharing contracts.
(b) Excludes the resale of purchased natural gas used in reservoir management.

The U.S. made the largest contribution to 2012 proved reserves increases, including 70 mmboe in purchases of reserves in place due to acquisitions in the Eagle Ford and 209 mmboe in extensions, discoveries and additions due to drilling programs within our shale plays. In addition, we added 45 mmboe in revisions of previous estimates in Canada due to technical analyses and a royalty change related to lower price realizations.

U.S. proved reserves increases in 2013 from extensions, discoveries and additions of 164 mmboe and revisions of previous estimates of 45 mmboe were the result of drilling programs in our shale plays. Revisions of previous estimates increased 36 mmboe in Canada primarily due to price and cost changes.

U.S. proved reserves increases in 2014 from extensions, discoveries and additions of 250 mmboe were the result of development activity in our U.S. resource plays. The sales of reserves in place related to our Norway and Angola discontinued operations were the largest decreases in 2014 proved reserves. The negative 55 mmboe revision to Canadian synthetic crude oil reserves primarily reflects the impact of technical and price changes on calculated royalty volumes as well as development plan changes in the mineable areas.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

	Year Ended December 31,											
(In millions)		U.S.		Canada		E.G.		Other Africa [a]		Other Int'l [b]		Total
2014 Capitalized Costs:												
Proved properties	$	28,334	$	9,481	$	1,804	$	823	$	5,707	$	46,149
Unproved properties		1,861		1,505		64		460		237		4,127
Total		30,195		10,986		1,868		1,283		5,944		50,276
Accumulated depreciation, depletion and amortization:												
Proved properties		13,746		1,183		1,010		260		5,075		21,274
Unproved properties		189		1		-		-		9		199
Total		13,935		1,184		1,010		260		5,084		21,473
Net capitalized costs	$	16,260	$	9,802	$	858	$	1,023	$	860	$	28,803
2013 Capitalized Costs:												
Proved properties	$	24,165	$	9,276	$	1,683	$	2,257	$	8,898	$	46,279
Unproved properties		2,097		1,508		31		693		510		4,839
Total		26,262		10,784		1,714		2,950		9,408		51,118
Accumulated depreciation, depletion and amortization:												
Proved properties		11,568		989		918		307		7,607		21,389
Unproved properties		180		1		-		13		15		209
Total		11,748		990		918		320		7,622		21,598
Net capitalized costs	$	14,514	$	9,794	$	796	$	2,630	$	1,786	$	29,520

(a) 2013 balances include capitalized costs related to Angola.
(b) 2013 balances include capitalized costs related to Norway.

Costs Incurred for Property Acquisition, Exploration and Development[a]

(In millions)		U.S.		Canada		E.G.		Other Africa		Other Int'l		Cont Ops		Disc Ops		Total
December 31, 2014																
Property acquisition:																
Proved	$	26	$	-	$	-	$	-	$	-	$	26	$	-	$	26
Unproved		202		3		-		53		2		260		1		261
Exploration		1,140		4		35		119		119		1,417		6		1,423
Development		3,532		196		139		16		94		3,977		418		4,395
Total	$	4,900	$	203	$	174	$	188	$	215	$	5,680	$	425	$	6,105
December 31, 2013																
Property acquisition:																
Proved	$	51	$	30	$	9	$	-	$	-	$	90	$	-	$	90
Unproved		157		-		-		44		21		222		-		222
Exploration		885		9		4		124		151		1,173		98		1,271
Development		2,876		280		84		46		83		3,369		499		3,868
Total	$	3,969	$	319	$	97	$	214	$	255	$	4,854	$	597	$	5,451
December 31, 2012																
Property acquisition:																
Proved	$	756	$	-	$	-	$	-	$	3	$	759	$	-	$	759
Unproved		432		-		18		63		(13)		500		5		505
Exploration		1,587		31		3		25		165		1,811		45		1,856
Development		2,469		195		22		15		164		2,865		662		3,527
Total	$	5,244	$	226	$	43	$	103	$	319	$	5,935	$	712	$	6,647

(a) Includes costs incurred whether capitalized or expensed.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

	U.S.	Canada	E.G.	Other Africa	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31, 2014								
Revenues and other income:								
Sales	$ 5,754	$ 1,316	$ 43	$ 244	$ 440	$ 7,797	$ 189	$ 7,986
Transfers	3	-	588	-	3	594	1,848	2,442
Other income[(a)]	(85)	-	-	-	-	(85)	1,832	1,747
Total revenues and other income	5,672	1,316	631	244	443	8,306	3,869	12,175
Expenses:								
Production costs	(1,544)	(803)	(154)	(79)	(253)	(2,833)	(181)	(3,014)
Exploration expenses	(607)	(1)	(26)	(103)	(56)	(793)	(5)	(798)
Depreciation, depletion and amortization[(b)]	(2,474)	(206)	(93)	(9)	(115)	(2,897)	(105)	(3,002)
Technical support and other	(193)	(15)	(31)	(21)	(14)	(274)	(7)	(281)
Total expenses	(4,818)	(1,025)	(304)	(212)	(438)	(6,797)	(298)	(7,095)
Results before income taxes	854	291	327	32	5	1,509	3,571	5,080
Income tax provision	(302)	(71)	(117)	(32)	(18)	(540)	(1,496)	(2,036)
Results of operations	$ 552	$ 220	$ 210	$ -	$ (13)	$ 969	$ 2,075	$ 3,044
Year Ended December 31, 2013								
Revenues and other income:								
Sales	$ 5,059	$ 1,376	$ 33	$ 1,106	$ 687	$ 8,261	$ 599	$ 8,860
Transfers	3	-	715	-	6	724	2,935	3,659
Other income[(a)]	(9)	-	-	-	(8)	(17)	-	(17)
Total revenues and other income	5,053	1,376	748	1,106	685	8,968	3,534	12,502
Expenses:								-
Production costs	(1,318)	(867)	(113)	(73)	(271)	(2,642)	(273)	(2,915)
Exploration expenses	(717)	(8)	(3)	(65)	(98)	(891)	(107)	(998)
Depreciation, depletion and amortization[(b)]	(1,980)	(218)	(97)	(28)	(151)	(2,474)	(345)	(2,819)
Technical support and other	(185)	(21)	(30)	(19)	(15)	(270)	(38)	(308)
Total expenses	(4,200)	(1,114)	(243)	(185)	(535)	(6,277)	(763)	(7,040)
Results before income taxes	853	262	505	921	150	2,691	2,771	5,462
Income tax provision	(323)	(66)	(182)	(920)	(117)	(1,608)	(1,948)	(3,556)
Results of operations	$ 530	$ 196	$ 323	$ 1	$ 33	$ 1,083	$ 823	$ 1,906
Year Ended December 31, 2012								
Revenues and other income:								
Sales	$ 3,879	$ 1,261	$ 29	$ 2,000	$ 738	$ 7,907	$ 97	$ 8,004
Transfers	2	-	818	-	-	820	3,601	4,421
Other income[(a)]	(8)	-	-	-	(32)	(40)	-	(40)
Total revenues and other income	3,873	1,261	847	2,000	706	8,687	3,698	12,385
Expenses:								-
Production costs	(1,054)	(826)	(141)	(58)	(222)	(2,301)	(188)	(2,489)
Exploration expenses	(558)	(30)	(5)	(10)	(82)	(685)	(27)	(712)
Depreciation, depletion and amortization[(b)]	(1,792)	(217)	(95)	(43)	(147)	(2,294)	(470)	- (2,764)
Technical support and other	(193)	(8)	(5)	(4)	(23)	(233)	(26)	(259)
Total expenses	(3,597)	(1,081)	(246)	(115)	(474)	(5,513)	(711)	(6,224)
Results before income taxes	276	180	601	1,885	232	3,174	2,987	6,161
Income tax provision	(100)	(45)	(210)	(1,795)	(189)	(2,339)	(2,260)	(4,599)
Results of operations	$ 176	$ 135	$ 391	$ 90	$ 43	$ 835	$ 727	$ 1,562

[(a)] Includes net gain (loss) on dispositions.
[(b)] Includes long-lived asset impairments.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of operations for oil and gas producing activities to segment income:

	Year Ended December 31,		
(In millions)	2014	2013	2012
Results of operations	$ 3,044	$ 1,906	$ 1,562
Discontinued operations	(2,075)	(823)	(727)
Results of continuing operations	969	1,083	835
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	73	40	42
Income from equity method investments	327	340	309
Items not allocated to segment income, net of tax:			
Loss on asset dispositions	58	20	31
Long-lived asset impairments	69	10	231
Segment income	$ 1,496	$ 1,493	$ 1,448

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

U.S. GAAP prescribes guidelines for computing the standardized measure of future net cash flows and changes therein relating to estimated proved reserves, giving very specific assumptions to be made such as the use of a 10 percent discount rate and an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month. These and other required assumptions have not always proved accurate in the past, and other valid assumptions would give rise to substantially different results. This information is not the fair value nor does it represent the expected present value of future cash flows of our crude oil and condensate, natural gas liquid, natural gas and synthetic crude oil reserves.

(In millions)	U.S.	Canada	E.G.	Other Africa	Other Int'l	Total
Year Ended December 31, 2014						
Future cash inflows	$ 66,307	$ 55,675	$ 5,027	$ 23,803	$ 3,040	$ 153,852
Future production and support costs	(19,504)	(34,838)	(1,270)	(803)	(1,452)	(57,867)
Future development costs	(14,626)	(9,754)	(259)	(680)	(1,669)	(26,988)
Future income tax expenses	(8,124)	(2,190)	(922)	(21,008)	(9)	(32,253)
Future net cash flows	$ 24,053	$ 8,893	$ 2,576	$ 1,312	$ (90) [(a)]	$ 36,744
10 percent annual discount for timing of cash flows	(12,138)	(6,613)	(915)	(742)	221	(20,187)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 11,915	$ 2,280	$ 1,661	$ 570	$ 131	$ 16,557
-related to discontinued operations	$ -	$ -	$ -	$ -	-	-
Year Ended December 31, 2013						
Future cash inflows	$ 54,099	$ 59,585	$ 5,911	$ 28,195	$ 3,178	$ 150,968
Future production and support costs	(16,774)	(35,954)	(1,619)	(976)	(1,191)	(56,514)
Future development costs	(9,685)	(9,694)	(367)	(793)	(1,302)	(21,841)
Future income tax expenses	(7,592)	(3,098)	(1,032)	(24,982)	(643)	(37,347)
Future net cash flows	$ 20,048	$ 10,839	$ 2,893	$ 1,444	$ 42	$ 35,266
10 percent annual discount for timing of cash flows	(9,940)	(8,300)	(1,084)	(828)	128	(20,024)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 10,108	$ 2,539	$ 1,809	$ 616	$ 170	$ 15,242
-related to discontinued operations	$ -	$ -	$ -	$ 1,302	$ 1,228	$ 2,530
Year Ended December 31, 2012						
Future cash inflows	$ 42,710	$ 55,171	$ 6,627	$ 28,173	$ 2,897	$ 135,578
Future production and support costs	(13,765)	(32,131)	(1,829)	(1,015)	(784)	(49,524)
Future development costs	(11,104)	(9,350)	(451)	(787)	(1,139)	(22,831)
Future income tax expenses	(4,489)	(2,948)	(1,191)	(25,020)	(827)	(34,475)
Future net cash flows	$ 13,352	$ 10,742	$ 3,156	$ 1,351	$ 147	$ 28,748
10 percent annual discount for timing of cash flows	(6,956)	(7,842)	(1,178)	(743)	59	(16,660)
Standardized measure of discounted future net cash flows-						
-related to continuing operations	$ 6,396	$ 2,900	$ 1,978	$ 608	$ 206	$ 12,088
-related to discontinued operations	$ -	$ -	$ -	$ 642	$ 1,489	$ 2,131

[(a)] Future cash flows for Other International reflects the impact of future abandonment costs related to the U.K.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
(In millions)	2014	2013	2012
Sales and transfers of oil and gas produced, net of production and support costs	$ (5,284)	$ (6,080)	$ (9,696)
Net changes in prices and production and support costs related to future production	(2,688) [(b)]	(336)	457
Extensions, discoveries and improved recovery, less related costs	3,539	3,415	2,763
Development costs incurred during the period	4,088	3,429	3,197
Changes in estimated future development costs	(1,423)	898	(135)
Revisions of previous quantity estimates[(a)]	(3,193) [(c)]	1,330	508
Net changes in purchases and sales of minerals in place	(168)	(229)	933
Accretion of discount	3,132	2,657	2,640
Net change in income taxes	3,312	(1,930)	12
Net change for the year	1,315	3,154	679
Beginning of the year related to continuing operations	15,242	12,088	11,409
End of the year related to continuing operations	$ 16,557	$ 15,242	$ 12,088
Net change for the year related to discontinued operations	$ (2,530)	$ 399	$ (242)

(a) Includes amounts resulting from changes in the timing of production.
(b) Decrease primarily due to lower realized prices related to Other Africa and Other International.
(c) Decrease mostly due to royalty adjustments on Canadian synthetic crude oil.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

	Year Ended December 31,		
(In millions)	2014	2013	2012
Segment Income			
North America E&P	$ 693	$ 529	$ 382
International E&P	568	758	895
Oil Sands Mining	235	206	171
Segment income	1,496	1,493	1,448
Items not allocated to segments, net of income taxes	(527)	(562)	(592)
Income from continuing operations	969	931	856
Discontinued operations[a]	2,077	822	726
Net income	$ 3,046	$ 1,753	$ 1,582
Capital Expenditures[b]			
North America E&P	$ 4,698	$ 3,649	$ 3,988
International E&P	534	456	235
Oil Sands Mining	212	286	188
Corporate	51	58	115
Discontinued operations[a]	390	535	605
Total	$ 5,885	$ 4,984	$ 5,131
Exploration Expenses			
North America E&P	$ 608	$ 725	$ 588
International E&P	185	166	97
Total	$ 793	$ 891	$ 685

(a) We closed the sale of our Angola assets in the first quarter of 2014 and our Norway business in the fourth quarter of 2014. The Angola assets and Norway business are reflected as discontinued operations in all periods presented.

(b) Capital expenditures include accruals.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

Net Sales Volumes	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(mbbld)*			
Bakken	45	35	27
Eagle Ford	72	51	23
Oklahoma Resource Basins	3	2	1
Other North America[(c)]	37	38	45
Total Crude Oil and Condensate	157	126	96
Natural Gas Liquids *(mbbld)*			
Bakken	3	2	1
Eagle Ford	19	14	5
Oklahoma Resource Basins	5	4	2
Other North America[(c)]	2	3	3
Total Natural Gas Liquids	29	23	11
Total Liquid Hydrocarbons *(mbbld)*			
Bakken	48	37	28
Eagle Ford	91	65	28
Oklahoma Resource Basins	8	6	3
Other North America[(c)]	39	41	48
Total Liquid Hydrocarbons	186	149	107
Natural Gas *(mmcfd)*			
Bakken	18	13	8
Eagle Ford	123	94	37
Oklahoma Resource Basins	61	48	32
Other North America[(c)]	108	157	281
Total Natural Gas	310	312	358
Equivalent Barrels *(mboed)*			
Bakken	51	39	29
Eagle Ford	112	81	34
Oklahoma Resource Basins	18	14	8
Other North America[(c)]	57	67	95
Total North America E&P *(mboed)*	238	201	166

[(c)] Includes Gulf of Mexico and other conventional onshore U.S. production, plus Alaska in 2013 and 2012.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

Net Sales Volumes	2014	2013	2012
International E&P			
Crude Oil and Condensate *(mbbld)*			
Equatorial Guinea	21	23	25
United Kingdom	11	14	15
Libya	7	24	42
Total Crude Oil and Condensate	39	61	82
Natural Gas Liquids *(mbbld)*			
Equatorial Guinea	10	11	11
United Kingdom	-	1	1
Total Natural Gas Liquids	10	12	12
Total Liquid Hydrocarbons *(mbbld)*			
Equatorial Guinea	31	34	36
United Kingdom	11	15	16
Libya	7	24	42
Total Liquid Hydrocarbons	49	73	94
Natural Gas *(mmcfd)*			
Equatorial Guinea	439	442	428
United Kingdom[(d)]	28	32	48
Libya	1	22	15
Total Natural Gas	468	496	491
Equivalent Barrels *(mboed)*			
Equatorial Guinea	104	107	107
United Kingdom[(d)]	16	20	24
Libya	7	28	45
Total International E&P *(mboed)*	127	155	176
Oil Sands Mining			
Synthetic Crude Oil *(mbbld)*[(e)]	50	48	47
Total Continuing Operations *(mboed)*	415	404	389
Discontinued Operations - Angola *(mboed)*[(a)]	2	10	-
Discontinued Operations - Norway *(mboed)*[(a)]	52	79	90
Total Company *(mboed)*	469	493	479
Net Sales Volumes of Equity Method Investees			
LNG *(mtd)*	6,535	6,548	6,290
Methanol *(mtd)*	1,092	1,249	1,298

(d) Includes natural gas acquired for injection and subsequent resale of 6 mmcfd, 7 mmcfd and 15 mmcfd for 2014, 2013, and 2012.
(e) Includes blendstocks.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

Average Price Realizations [f]	2014	2013	2012
North America E&P			
Crude Oil and Condensate *(per bbl)*			
Bakken	$81.63	$90.25	$83.11
Eagle Ford	87.99	99.69	100.14
Oklahoma Resource Basins	87.15	94.84	89.26
Other North America[c]	84.21	90.42	91.75
Total Crude Oil and Condensate	85.25	94.19	91.30
Natural Gas Liquids *(per bbl)*			
Bakken	$43.25	$41.60	$42.35
Eagle Ford	29.60	30.16	32.96
Oklahoma Resource Basins	32.61	35.28	31.82
Other North America[c]	51.12	55.69	52.51
Total Natural Gas Liquids	33.42	35.12	39.57
Total Liquid Hydrocarbons *(per bbl)* [f]			
Bakken	$79.41	$87.76	$81.36
Eagle Ford	75.83	84.95	88.09
Oklahoma Resource Basins	50.86	50.77	49.21
Other North America[c]	81.88	88.16	89.03
Total Liquid Hydrocarbons	77.02	85.20	85.80
Natural Gas *(per mcf)*			
Bakken	$5.28	$3.90	$3.11
Eagle Ford	4.43	3.67	3.03
Oklahoma Resource Basins	4.49	3.78	3.05
Other North America[c]	4.65	3.95	4.20
Total Natural Gas	4.57	3.84	3.92

[f] Excludes gains or losses on derivative instruments. Inclusion of realized gains (losses) on crude oil derivative instruments would have increased (decreased) average liquid hydrocarbon price realizations per barrel by $(0.27) and $0.40 for 2013 and 2012. There were no crude oil derivative instruments for 2014.

MARATHON OIL CORPORATION
Supplemental Statistics (Unaudited)

Average Price Realizations	2014	2013	2012
International E&P			
Crude Oil and Condensate *(per bbl)*			
Equatorial Guinea	$81.01	$90.62	$92.56
United Kingdom	94.31	110.76	109.50
Libya	94.70	122.92	127.31
Other International	-	-	-
Total Crude Oil and Condensate	87.23	108.18	113.61
Natural Gas Liquids *(per bbl)*			
Equatorial Guinea[g]	$1.00	$1.00	$1.00
United Kingdom	67.73	72.14	78.81
Libya	-	-	-
Other International	-	-	-
Total Natural Gas Liquids	2.46	5.24	8.32
Total Liquid Hydrocarbons *(per bbl)*			
Equatorial Guinea	$54.29	$60.34	$64.33
United Kingdom	93.75	108.92	107.31
Libya	94.70	122.92	127.31
Other International	-	-	-
Total Liquid Hydrocarbons	68.98	91.04	100.02
Natural Gas *(per mcf)*			
Equatorial Guinea[g]	$0.24	$0.24	$0.24
United Kingdom	8.27	10.64	9.72
Libya	3.11	5.44	5.76
Other International	-	-	-
Total Natural Gas	0.72	1.15	1.33
Oil Sands Mining			
Synthetic Crude Oil *(per bbl)*	$83.35	$87.51	$81.72
Discontinued Operations - Angola *(per boe)*[a]	99.82	104.77	-
Discontinued Operations - Norway *(per boe)*[a]	104.22	109.60	111.82
Total Proved Reserves (at year end)			
Crude Oil and Condensate *(mmbbl)*			
North America E&P	634	497	387
International E&P	294	304	305
Total Crude Oil and Condensate	928	801	692
Natural Gas Liquids *(mmbbl)*			
North America E&P	161	119	88
International E&P	31	35	39
Total Natural Gas Liquids	192	154	127
Natural Gas *(bcf)*			
North America E&P	1,144	1,025	1,043
International E&P	1,436	1,553	1,647
Total Natural Gas	2,580	2,578	2,690
Synthetic Crude Oil *(mmbbl)*			
Oil Sands Mining	648	680	653
Total Continuing Operations *(mmboe)*	2,198	2,065	1,920
Discontinued Operations *(mmboe)*[a]	-	106	97
Total Proved Reserves *(mmboe)*	2,198	2,171	2,017

[g] Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International E&P segment.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2014.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See "Report of Independent Registered Public Accounting Firm" under Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2014, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is incorporated by reference to "Election of Directors," "Corporate Governance-Committees of the Board" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2015 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2014 (the "2015 Proxy Statement").

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for information about our executive officers.

Our Code of Business Conduct and the Code of Ethics for Senior Financial Officers are available on our website at www.marathonoil.com.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to "Corporate Governance-Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the 2015 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Portions of information required by this item are incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management" in the 2015 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2014 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan")
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") - No additional awards will be granted under this plan.
- Marathon Oil Corporation 2003 Incentive Compensation Plan (the "2003 Plan") - No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors - No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[(c)]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	14,453,729 [(a)]	$29.68	45,489,820 [(d)]
Equity compensation plans not approved by stockholders	20,984 [(b)]	N/A	-
Total	14,474,713	N/A	45,489,820

(a) Includes the following:
- 3,237,349 stock options outstanding under the 2012 Plan; 9,106,352 stock options outstanding under the 2007 Plan; 1,084,135 stock options outstanding under the 2003 Plan;
- 355,709 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2012 Plan, 2007 Plan and 2003 Plan; common stock units credited under the 2012 Plan, 2007 Plan and 2003 Plan were 82,233, 222,215 and 51,261, respectively;
- 670,184 restricted stock units granted to non-officers under the 2012 Plan and 2007 Plan and outstanding as of December 31, 2014.

In addition to the awards reported above 200,444 and 2,577,725 shares of restricted stock were issued and outstanding as of December 31, 2014, but subject to forfeiture restrictions under the 2007 Plan and 2012 Plan, respectively.

(b) Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon Oil common stock in place of the common stock units.

(c) The weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(d) Reflects the shares available for issuance under the 2012 Plan. No more than 18,949,438 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, canceled or expire unexercised shall again immediately become available for issuance.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to "Transactions with Related Persons," and "Corporate Governance-Director Independence" in the 2015 Proxy Statement.

Item 14. Principal Accountant Fees and Services

Information required by this item is incorporated by reference to "Ratification of Independent Auditor for 2015" in the 2015 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements - See Part II, Item 8. of this Annual Report on Form 10-K.

2. Financial Statement Schedules - Financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.

3. Exhibits - The information required by this Item 15 is incorporated by reference to the Exhibit Index accompanying this Annual Report on Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

March 2, 2015 MARATHON OIL CORPORATION

By: /s/ GARY E. WILSON

Gary E. Wilson

Vice President, Controller and Chief Accounting Officer

POWER OF ATTORNEY

Each person whose signature appears below appoints Lee M. Tillman, John R. Sult, and Gary E. Wilson, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, with full power and authority to each of said attorneys-in-fact and agents to do and perform each and every act whatsoever that is necessary, appropriate or advisable in connection with any or all of the above-described matters and to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on March 2, 2015 on behalf of the registrant and in the capacities indicated.

Signature	Title
/S/ LEE M. TILLMAN Lee M. Tillman	President and Chief Executive Officer and Director
/S/ JOHN R. SULT John R. Sult	Executive Vice President and Chief Financial Officer
/s/ GARY E. WILSON Gary E. Wilson	Vice President, Controller and Chief Accounting Officer
/S/ DENNIS H. REILLEY Dennis H. Reilley	Chairman of the Board
/S/ GREGORY H. BOYCE Gregory H. Boyce	Director
/S/ PIERRE BRONDEAU Pierre Brondeau	Director
/S/ CHADWICK C. DEATON Chadwick C. Deaton	Director
/S/ MARCELA E. DONADIO Marcela E. Donadio	Director
/S/ SHIRLEY ANN JACKSON Shirley Ann Jackson	Director
/S/ PHILIP LADER Philip Lader	Director
/S/ MICHAEL E. J. PHELPS Michael E. J. Phelps	Director

Exhibit Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date
3	**Articles of Incorporation and Bylaws**			
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	10-Q	3.1	8/8/2013
3.2	Amended By-Laws of Marathon Oil Corporation effective February 25, 2014	10-K	3.2	2/28/2014
3.3	Specimen of Common Stock Certificate	10-K	3.3	2/28/2014
4	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10 percent of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request	10-K	4.2	2/28/2014
10	**Material Contracts**			
10.1	Amended and Restated Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, as borrower, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	8-K	4.1	6/2/2014
10.2†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012
10.3†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.4†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Section 16 Officers	10-Q	10.1	5/7/2014
10.5†	Form of Performance Unit Award Agreement 2014 - 2016 Performance Cycle for Officers	10-Q	10.2	5/7/2014
10.6†	Form of Initial CEO Option Grant Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	11/6/2013
10.7†	Form of CEO Restricted Stock Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-Q	10.2	11/6/2013
10.8†	Form of CEO Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-Q	10.3	11/6/2013
10.9†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.1	5/10/2013
10.10†	Form of Performance Unit Award Agreement (2013-2015 Performance Cycle) for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan	10-Q	10.2	5/10/2013
10.11†	Form of Nonqualified Stock Option Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.5	2/22/2013

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
10.12†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.6	2/22/2013
10.13†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.7	2/22/2013
10.14†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year cliff vesting)	10-K	10.8	2/22/2013
10.15†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.9	2/22/2013
10.16†	Form of Restricted Stock Award Agreement for Officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.10	2/22/2013
10.17†	Form of Nonqualified Stock Option Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.11	2/22/2013
10.18†	Form of Nonqualified Stock Option Award Agreement for non-officers in Canada granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.12	2/22/2013
10.19†	Form of Restricted Stock Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.13	2/22/2013
10.20†	Form of Restricted Stock Unit Award Agreement for non-officers granted under the Marathon Oil Corporation 2012 Incentive Compensation Plan (3-year prorata vesting)	10-K	10.14	2/22/2013
10.21†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.22†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.6	2/29/2012
10.23†	Form of Officer Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.8	2/29/2012
10.24†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/28/2011
10.25†	Form of Officer Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.7	2/28/2011
10.26†	Form of Performance Unit Award Agreement (2012-2014 Performance Cycle) granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan.	10-Q	10.2	5/4/2012
10.27†	Form of Restricted Stock Award Agreement for Section 16 Officers granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan.	10-K	10.27	2/26/2010
10.28†	Form of Nonqualified Stock Option Award Agreement granted under the Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.26	2/26/2010
10.29†	Marathon Oil Corporation 2003 Incentive Compensation Plan, Effective January 1, 2003	10-K	10.9	2/26/2010

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Exhibit	Filing Date
10.30†	Form of Nonqualified Stock Option Award Agreement for Officers granted under the Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.22	2/26/2010
10.31†	Form of Officer Restricted Stock Award Agreement granted under the Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.23	2/26/2010
10.32	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of January 1, 2012)	10-Q	10.3	5/7/2014
10.33†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.34†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.35†	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (For Officers Hired or Promoted after October 26, 2011)	10-Q	10.4	5/4/2012
10.36*†	Marathon Oil Corporation 2011 Officer Change in Control Severance Benefits Plan (as amended, effective November 1, 2014)			
10.37†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.38†	Marathon Oil Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009
10.39†	Marathon Oil Corporation Bonus Agreement Upon Commencement of Employment for Lee M. Tillman	10-Q	10.4	11/6/2013
10.40	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011
12.1*	Computation of Ratio of Earnings to Fixed Charges			
14.1	Code of Ethics for Senior Financial Officers	10-K	14.1	2/26/2010
21.1*	List of Significant Subsidiaries			
23.1*	Consent of Independent Registered Public Accounting Firm			
23.2*	Consent of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists			
23.3*	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists			
23.4*	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists			
31.1*	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
31.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
32.1*	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350			
32.2*	Certification of Executive Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350			
99.1*	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2014			
99.2	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2013	10-K	99.1	2/28/2014
99.3	Report of GLJ Petroleum Consultants LTD., independent petroleum engineers and geologists for 2012	10-K	99.1	2/22/2013

Exhibit Number	Exhibit Description	Incorporated by Reference		
		Form	Exhibit	Filing Date
99.4*	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2014			
99.5	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2013	10-K	99.4	2/28/2014
99.6	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2012	10-K	99.4	2/22/2013
99.7*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2014			
99.8	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2013	10-K	99.7	2/28/2014
99.9	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2012	10-K	99.6	2/22/2013
101.INS*	XBRL Instance Document			
101.SCH*	XBRL Taxonomy Extension Schema			
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase			
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase			
101.LAB*	XBRL Taxonomy Extension Label Linkbase			
101.DEF*	XBRL Taxonomy Extension Definition Linkbase			
*	Filed herewith.			
**	Furnished, not filed.			
†	Management contract or compensatory plan or arrangement.			

Exhibit 89

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported): March 3, 2015

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	1-8968	76-0146568
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

On March 3, 2015, Anadarko Petroleum Corporation (Anadarko) announced its 2015 capital budget and provided guidance for 2015. The press release is included in this report as Exhibit 99 and is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99 Anadarko Press Release dated March 3, 2015.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

March 3, 2015

By: /s/ M. CATHY DOUGLAS
M. Cathy Douglas
Senior Vice President, Chief Accounting Officer and Controller

EXHIBIT INDEX

Exhibit No.	Description
99	Anadarko Press Release dated March 3, 2015.

Exhibit 99

Petroleum Corporation

NEWS

ANADARKO ANNOUNCES 2015 CAPITAL PROGRAM AND GUIDANCE

HOUSTON, March 3, 2015 - Anadarko Petroleum Corporation (NYSE: APC) today announced its 2015 initial capital expectations and guidance, concurrent with its 2015 Investor Conference Call.

2015 INVESTOR CONFERENCE CALL HIGHLIGHTS

- Anticipates approximately 5-percent year-over-year oil sales-volume growth in 2015, on a divestiture-adjusted basis[1]
- Forecasts improved 2015 liquids product mix of approximately 50 percent, even with the reduction of more than 9 million net barrels of oil equivalent (BOE) of assumed ethane rejection
- Establishes net resources of more than 1 billion BOE in the Wolfcamp Shale
- Achieves first oil at the 80,000-barrels-of-oil-per-day Lucius spar and enhances value through new production-handling agreement
- Announces more than $700 million of asset monetizations to date in 2015

"During 2015, we are confident in our ability to leverage our deep, high-quality portfolio of opportunities, strong balance sheet and efficient capital allocation to preserve value and maintain flexibility," said Anadarko Chairman, President and CEO Al Walker. "Few companies have accomplished operationally what Anadarko has achieved over the last five years; although, in the current market, we believe it is prudent to reduce capital investments and position the company for the future, rather than to pursue year-over-year growth. As a result, we've reduced our initial 2015 capital expectations by approximately 33 percent relative to last year, with plans to reduce our short-cycle U.S. onshore rig activity by 40 percent and defer approximately 125 onshore well completions. We have successfully delivered value during previous challenging commodity-price cycles, and I believe we have the skills, financial capacity and portfolio to deliver in this environment. Our focus continues to be on getting better, not necessarily bigger, while ensuring we are well positioned to accelerate activity as costs become more aligned with commodity prices and returns improve."

2015 INITIAL SALES-VOLUME AND CAPITAL EXPECTATIONS

Divestiture-Adjusted[1] Sales-Volume Expectations

2014	2015 Productive Capacity[2]	2015 Initial Expectations
301 MMBOE	308 - 314 MMBOE	295 - 301 MMBOE

(1) *"Divestiture-Adjusted" sales volumes reflect Anadarko's continuing asset base, giving effect to recent divestitures. For a reconciliation, see the table on page eight attached to this release.*

(2) *"Productive Capacity" is intended to represent what the portfolio could produce within the current 2015 capital budget range if the company did not elect to reject approximately 9 million BOE of ethane and choose to defer approximately 4 million BOE related to reduced U.S. onshore well completions.*

Initial Capital Expectations ($5.4 - $5.8 Billion)*

By Cash Cycle		By Area	
Short Cash Cycle	55%	U.S. Onshore	60%
Mid Cash Cycle	30%	Int'l & Deepwater Operations	22%
Long Cash Cycle	12%	Int'l & Deepwater Exploration	10%
Corporate	3%	Midstream & Other	8%

* *Does not include capital investments by Western Gas Partners, LP (NYSE: WES); all percentages are approximates.*

SHORT CASH CYCLE

Anadarko's Wattenberg Horizontal program continues to generate some of the strongest U.S. onshore returns in the industry, primarily as a result of the company's consolidated core acreage position, expansive infrastructure and minerals-interest ownership. The resilient economics of the Wattenberg field continue to make it an attractive place to invest in 2015 as it generates better than 30-percent before-tax rates of return at current strip prices. Additionally, the company plans to allocate capital toward its Eagleford Shale activity which, at current strip prices, generates before-tax rates of return of more than 20 percent.

MID CASH CYCLE

Anadarko remains committed to investing in assets that are expected to generate significant growth in the next one to three years. Among these assets is the Wolfcamp Shale in the Delaware Basin of West Texas, where the company is applying its proven integrated midstream approach to build the foundation for future growth. As a result of the company's delineation activities to date, Anadarko has established a net resource

estimate of more than 1 billion BOE with more than 5,000 identified drilling locations in the heart of the Wolfcamp Shale oil play. Additionally, Anadarko is leveraging its hub-and-spoke philosophy at its Lucius spar in the deepwater Gulf of Mexico by reaching a new production-handling agreement for the nearby third-party Buckskin/Moccasin project, while continuing to advance development of the Heidelberg and TEN mega projects in the Gulf of Mexico and offshore Ghana, respectively, toward first production in 2016.

LONG CASH CYCLE

In 2015, Anadarko expects to drill nine to 12 deepwater exploration/appraisal wells focusing on play-opening exploration opportunities in Colombia, Kenya and the Gulf of Mexico. Additionally, Anadarko continues to advance existing discoveries at Shenandoah in the Gulf of Mexico and Paon offshore Côte d'Ivoire toward commerciality, while continuing to progress its Mozambique LNG project.

Four pages of supplemental materials including the company's 2015 initial guidance, updated hedging positions and a reconciliation of divestiture-adjusted sales volumes are provided in the tables attached to this release.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2014, the company had approximately 2.86 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and APC Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to meet financial and operating guidance; to meet the objectives identified in this news release; to consummate the transaction described in this news release; to execute the 2015 capital program; to drill, develop and commercially operate the drilling prospects identified in this news release; to achieve production and budget expectations on its mega projects; and to successfully plan, secure necessary government approvals, finance, build and operate the necessary structure and an LNG park. See "Risk Factors" in the company's 2014 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

Cautionary Note to Investors: The United States Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms. Anadarko uses certain terms in this news release, such as "net resources," "net resource estimate," and similar terms that the SEC's guidelines strictly prohibit Anadarko from including in filings with the SEC. U.S. investors are urged to consider closely the disclosure in Anadarko's Form 10-K for the year ended Dec. 31, 2014, File No. 001-08968, available from Anadarko at www.anadarko.com or by writing Anadarko at: Anadarko Petroleum Corporation, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, Attn: Investor Relations. This form may also be obtained by contacting the SEC at 1-800-SEC-0330.

# # #

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Anadarko Petroleum Corporation
Financial and Operating External Guidance
March 3, 2015

	1st-Qtr Guidance			Full-Year Guidance		
	Units			Units		
Total Sales Volumes (MMBOE)	79	—	82	295	—	301
Total Sales Volumes (MBOE/d)	878	—	907	808	—	826
Crude Oil (MBbl/d)	300	—	308	285	—	293
United States	206	—	210	200	—	204
Algeria	66	—	68	63	—	65
Ghana	28	—	30	22	—	24
Natural Gas (MMcf/d)						
United States	2,675	—	2,725	2,425	—	2,475
Natural Gas Liquids (MBbl/d)						
United States	125	—	135	109	—	117
Algeria	6	—	8	4	—	6

	$ / Unit			$ / Unit		
Price Differentials vs. NYMEX (w/o hedges)						
Crude Oil ($/Bbl)	(3.00)	—	(1.00)	(3.00)	—	(1.00)
United States	(6.00)	—	(1.00)	(6.00)	—	(1.00)
Algeria	2.00	—	5.00	2.00	—	5.00
Ghana	—	—	2.00	—	—	3.00
Natural Gas ($/Mcf)						
United States	(0.50)	—	(0.25)	(0.60)	—	(0.30)

Anadarko Petroleum Corporation
Financial and Operating External Guidance
March 3, 2015

	1st-Qtr Guidance			Full-Year Guidance		
	$ MM			$ MM		
Other Revenues						
Marketing and Gathering Margin	30	—	50	140	—	160
Minerals and Other	85	—	95	310	—	330
Costs and Expenses						
	$ / BOE			$ / BOE		
Oil & Gas Direct Operating	3.80	—	4.00	3.60	—	4.00
Oil & Gas Transportation/Other	3.50	—	3.70	3.70	—	3.90
Depreciation, Depletion and Amortization	14.50	—	15.00	15.25	—	15.75
Production Taxes (% of Product Revenue)	8.0%	—	9.0%	8.5%	—	9.5%
	$ MM			$ MM		
General and Administrative	310	—	330	1,250	—	1,300
Exploration Expense						
Non-Cash	80	—	100	550	—	600
Cash	75	—	95	375	—	400
Interest Expense (net)	205	—	215	800	—	820
Other (Income) Expense	40	—	50	150	—	200
Taxes						
Algeria (All current)	55%	—	60%	55%	—	60%
Rest of Company (Expect significant current-tax benefit)	10%	—	15%	25%	—	30%
Avg. Shares Outstanding (MM)						
Basic	507	—	508	508	—	509
Diluted	509	—	510	510	—	511
Capital Investment (Excluding Western Gas Partners, LP)	$ MM			$ MM		
APC Capital Expenditures	1,700	—	1,900	5,400	—	5,800

Anadarko Petroleum Corporation
Commodity Hedge Positions (Excluding Natural Gas Basis)
As of March 3, 2015

	Volume (Thousand MMBtu/d)	Weighted Average Price per MMBtu		
		Floor Sold	Floor Purchased	Ceiling Sold
Natural Gas				
Three-Way Collars				
2015	635	$ 2.75	$ 3.75	$ 4.76
Extendable Fixed Price - Financial				
2015*	170	$ 4.17		

* Includes an option for the counterparty to extend the contract term to December 2016 at the same price.

Interest-Rate Derivatives
As of March 3, 2015

Instrument	Notional Amt.	Start Date	Maturity	Rate Paid	Rate Received
Swap	$50 Million	Sept. 2016	Sept. 2026	5.91%	3M LIBOR
Swap	$1,850 Million	Sept. 2016	Sept. 2046	6.05%	3M LIBOR

Anadarko Petroleum Corporation
Reconciliation of Divestiture-Adjusted Sales Volumes

Average Daily Sales Volumes

	Natural Gas MMcf/d	Crude Oil & Condensate MBbls/d	NGLs MBbls/d	Total MBOE/d
Quarter Ended March 31, 2014				
U.S. Onshore	2,396	112	92	604
Deepwater Gulf of Mexico	275	46	6	98
International and Alaska	—	87	—	87
Divestiture-Adjusted Sales	2,671	245	98	789
China, Pinedale/Jonah and EOR	26	25	1	30
Total	2,697	270	99	819
Quarter Ended June 30, 2014				
U.S. Onshore	2,443	134	113	655
Deepwater Gulf of Mexico	176	41	6	76
International and Alaska	—	101	1	102
Divestiture-Adjusted Sales	2,619	276	120	833
China, Pinedale/Jonah and EOR	1	15	—	15
Total	2,620	291	120	848
Quarter Ended Sept. 30, 2014				
U.S. Onshore	2,339	145	124	659
Deepwater Gulf of Mexico	154	46	5	77
International and Alaska	—	98	1	99
Divestiture-Adjusted Sales	2,493	289	130	835
China, Pinedale/Jonah and EOR	1	14	—	14
Total	2,494	303	130	849
Quarter Ended Dec. 31, 2014				
U.S. Onshore	2,369	151	113	659
Deepwater Gulf of Mexico	179	47	6	83
International and Alaska	—	88	10	98
Divestiture-Adjusted Sales	2,548	286	129	840
China, Pinedale/Jonah and EOR	1	14	—	14
Total	2,549	300	129	854
Year Ended Dec. 31, 2014				
U.S. Onshore	2,386	136	111	644
Deepwater Gulf of Mexico	196	45	5	83
International and Alaska	—	94	3	97
Divestiture-Adjusted Sales	2,582	275	119	824
China, Pinedale/Jonah and EOR	7	17	—	19
Total	2,589	292	119	843

Note: EOR transaction pending

Exhibit 90

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

APC - Anadarko Petroleum Corp 2015 Capital Program and Guidance Call

EVENT DATE/TIME: MARCH 03, 2015 / 2:00PM GMT

OVERVIEW:

APC provided an update on its 2015 capital program and guidance.

Exhibit
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THOMSON REUTERS

CORPORATE PARTICIPANTS

John Colglazier *Anadarko Petroleum Corporation - VP of IR and Communications*

Al Walker *Anadarko Petroleum Corporation - Chairman, President & CEO*

Bob Gwin *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Chuck Meloy *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Jim Kleckner *Anadarko Petroleum Corporation - EVP of International and Deepwater Operations*

Bob Daniels *Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

CONFERENCE CALL PARTICIPANTS

Doug Leggate *BofA Merrill Lynch - Analyst*

Brian Singer *Goldman Sachs - Analyst*

Subash Chandra *Guggenheim - Analyst*

Paul Sankey *Wolfe Research - Analyst*

Charles Meade *Johnson Rice & Company - Analyst*

Jeffrey Lambujon *Tudor, Pickering, Holt & Company - Analyst*

John Herrlin *Societe Generale - Analyst*

David Heikkinen *Heikkinen Energy Advisors - Analyst*

PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to the APC 2015 capital program and guidance conference call.

(Operator Instructions)

I would now like to turn the conference over to your host for today, to Mr. John Colglazier. You may begin. Sir, you may begin. Your line is open.

John Colglazier - *Anadarko Petroleum Corporation - VP of IR and Communications*

Where we are discussing our portfolio guidance and key metrics. Over the next hour or so, our executives will provide a review of our deep portfolio, and discuss the decisions and actions taken in the current environment to preserve value and position ourselves for the future. At the end of the presentation, our executive team will be available to take your questions. In a few minutes, I'll turn the call over to Al Walker.

But first, I need to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures. And there are a number of factors which could cause actual results to differ materially from what we discuss today. We encourage you to read our full disclosure on forward-looking statements, and the GAAP reconciliations, located on our website and attached to this morning's earnings release -- or news release. With that, I'll turn the call over to Al.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Thank you, John, and good morning. I would like to thank everyone for taking the time to join us this morning. A few weeks ago, during our earnings call, we discussed our outstanding operating results for 2014. I talked briefly about the outlook for the coming year, and what this means for Anadarko. Today, we look forward to sharing our strategy, objectives, tactics, preserving value and positioning APC for differentiated success in the future. As many of you appreciate, we design our portfolio and capital allocation process to provide strong growth during periods of attractive well economics, and resiliency during those times when our commodity prices and service calls are [outstanding].

Our operating results for the last five years demonstrate we can deliver very attractive growth when our capital can be deployed, the market environment where we expect rates of returns for this objective. And we believe we can distinguish ourselves through the opportunities we see in the current challenging environment, much like we did not so long ago, in late 2008 into 2009. If anything, we understand our industry is cyclical, and our Company and management team have successfully managed downturns before. This time, Anadarko is even in a better position to do so again.

We believe our geographic diversity of our assets, the enhancements we make to our liquids product, and our differentiating approach to capital allocation and portfolio management, really sets us apart. As you can see, the five-year track record is pretty substantial. I have made reference to our successful record in the past, and you can see in the graphic our results support the confidence I've expressed. Our employees have done an incredible job focusing on our objectives and goals and then delivering. I'm proud to say we have consistently met or exceeded each one.

Exceeding 5% to 7% compounded annual growth, exceeding greatly the significant free cash flow objectives we set for ourselves, consistently replacing more than 160% of production at very competitive cost, and continuing exploration success that ranks among the most elite in our business. Throughout this process, we've never been shy about accelerating value when the opportunity is right, monetizing well over $12 billion of value. Our portfolio provides many advantages. In particular, the balance between unconventional and large-scale conventional oil projects in the Deepwater and international.

One of these advantages to our portfolio is a lower inherent base decline of less than 20% that results in lower maintenance capital requirements. Consider the last five years, where we significantly increased our growth, particularly in short cycle oil volumes, continued funding of our longer dated activities, and generated strong free cash flow in each year. In 2015, we estimate maintenance capital to be a little more than $3 billion, which assumes very little in the way of service cost reductions. While we expect service cost will eventually sync up with commodities, we have not assume this to be material in 2015, and expect this impact will more likely be evident in the full-year results of 2016.

This advantage allows flexibility in our capital structure, and allocation of capital, to accelerate short cycle growth in the United States onshore when costs better aligned with commodity prices. Our top-tier activation cost enables tremendous growth, with every $1 billion of growth capital providing almost 35,000 Boe per day in the current growth year. Beyond the depth and the quality of our portfolio and proven track record, a key differentiator for us is our approach to capital allocation. First and foremost, when it comes to allocating capital, we grow organically versus acquisitions. We'll continue to fund long cycle exploration, as we believe this creates tremendous option value for our Company.

Because of our exploration success, we've created an enviable pipeline, adding much in the way of value-added time margin assets with our Deepwater and international projects. Anadarko's US onshore success, and future opportunities, have the ability to flex our capital allocations to preserve or accelerate value. This, of course, depends on well head economics, and Chuck will talk more about this in a few minutes, as we (inaudible) to many of our US assets. I'd like to point out, year over year, our US onshore grew from a base of 565,000 Boe per day in 2013, to more than 657,000 Boe in 2014. That's more than 90,000 Boe of growth, for less than $6 billion, on a divestiture adjusted basis.

This commercial focus sets us apart, and solidifies our position among those capital efficient allocators in the business. We will also establish a competitive edge in a number of other areas: exploration, appraisal and exploitation. Our industry-leading exploration and appraisal success has delivered more than 4 billion Boe of net risk resources to the Company in the last five years, which does not include significant Wattenberg [un-booked] upside, and emerging Wolfcamp shale in the Delaware Basin, just to name a few. Project management has always been one of the most important things we been able to achieve at Anadarko.

Our track record of speed and efficiency, and significant value, versus others in the industry, with industry-leading capability, was once again evident by achieving first oil at Lucius just three years from sanction, which you will hear more about this morning. Our ministry. Controlling evacuation and infrastructure are keys to maximizing value of our production. It also facilitates growth, as you can see in our unmatched results at the Wattenberg last year, and will again in the Delaware, as we begin loading that spring in very much the same way. It also ensures our ability to maximize margins, which creates tremendous value through both WES and WGP, which currently has a market value to APC of around $12 billion.

Our mineral interests. The benefits are immense, and even more magnified in today's environment, both in terms of value uplift, capital efficiency and knowledge. I can't think of another company that manages its portfolio the way we do. We have been more proactive in our approach to portfolio management than any company in our industry for the last 10 years, and you can see in the graphic, we've been act managers for the last five years, so delivering the strong operating results, as seen in this graphic. We leverage our exploration through farm-outs, and carries utilizing third-party money, and we do this with our assets, as well. Capital efficient, tax efficient, carried interest on both onshore and offshore, are keys to our success.

These [grids] have enabled us to reduce capital obligations and execution risk, while significantly enhancing project returns. They also provide additional flexibility to reallocate capital to short cycle growth opportunities. Another tactical aspect of our philosophy is the continued high grade of the portfolio. Identifying those opportunities where we see limited growth or value in our equity story. The $12.5 billion of monetization shown in this graphic does not include the more than $3 billion we've received in cash from WES and WGP. You should expect this to continue accelerating value through an active portfolio management.

We have shown, the last five years, we can be very, very good on offense. And we are demonstrating the same tenacity, as we transition to the opportunities the current environment affords us. You'll hear from our executive team this morning, as we discuss the areas of responsibility -- through the areas of their responsibilities, and we have [built] the financial capacity and the work ethic to create value in this very difficult market. We methodically built a portfolio that has tremendous option value and durability. And when commodity prices once again sneak up in cost, we look forward to playing the type of offense we did the last five years, and doing it well. As demonstrated in 2014, our portfolio is capable of tremendous growth.

However, we don't see value in chasing growth in this environment, which is why we are choosing to preserve value over the longer-term. We view our capital allocation process as dynamic. As such, we will slow our growth by reducing our operating rig count. We will differ about 125 completions until costs align with revenues. We will be judicious with capital allocation and economic (inaudible) recover ethane to maximize revenues. This capital allocation results in a strong year-over-year 5% growth and higher value oil volumes. And we believe we are conservative in only embedding cost savings and reductions which we have realized in the first two months of this year.

Just a quick additional note on this slide. A lot of folks have been trying to figure out what our 2015 exit rate will be. And though we expect to be slightly down year over year, the decrease will be comprised of lower margin gas and lower ethane volumes. Our exit rate for oil volumes are anticipated to be relatively flat with the fourth quarter of last year. Regardless of commodity prices, our objectives have always been to be a better company, not necessarily a bigger company. As I wrap up, and before handing off to Bob Gwin, I want to express the confidence that we have in all the things I've mentioned.

We're making the right decisions at the right time to maintain flexibility and preserve value. This environment is changing, and it's challenging. We also think it affords us lots of opportunities, which is why we're going into this with our eyes wide open, and be very focused. Past cycles have shown these are times when companies can differentiate and create value for their shareholders. We're confident we can do that. Bob?

Bob Gwin - *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Thanks, Al. Good morning, everybody. I'm going to build upon some of Al's comments this morning. I wanted to start off taking a look at the financial position. We finished last year, 2014, in a very strong place, with $7.4 billion of cash on the balance sheet. And as many of you know, we made the payments, the $5.2 billion payment on the Tronox settlement. And with that, and the announced asset sale this morning, we're still going to have approximately $3 billion of cash on a pro forma basis.

Then beyond this cash position, we have a lot of additional liquidity. We have new -- $5 billion of new credit facilities, and a new commercial paper program in place, as afforded to us by our stronger credit ratings. You can see the credit ratings to the right. On a pro forma basis, our net debt-to-cap ratio has been a targeted range. And these -- the upgrade of Moody's in February puts us in a position where these were our strongest credit ratings in over nine years. Our focus on portfolio management and monetizing assets has been a key part of our financial strategy for several years.

And as Al mentioned, we continue that execution into 2015, with over $700 million of divestitures that we've announced this morning. And if you look at this, along with our anticipated cash flows, our 2015 capital program that Al has just announced is fully funded without stretching the balance sheet. I think the key takeaway from this slide is that, with our cash flow, our liquidity, and our ability to monetize assets, Anadarko's 2015 capital program is fully funded. And I want to make it clear that we have no need or plans to access the capital markets this year. We believe we are very well-positioned to manage through the commodity price downturn, even if it becomes protracted.

I'd also like to take a minute to talk about Western Gas and WGP, which are our sponsored MLP. These continue to be fantastic value creators for APC, and for the shareholders and unit holders of all three of these entities. WES's finances its activities independently, through its own debt and equity issuances, which are of course non-dilutive equity issuances to APC's shareholders. And it supports APC's competitive advantage in midstream that Al highlighted, through substantial capital investment. Last year, for instance, WES spent over $725 million on midstream expansion, while APC spent around $350 million.

WES's spending can be organic, like the construction and expansion of the Lancaster facilities, which support the growth in the Wattenberg field. Or they can be opportunistic, like the acquisition of Nuevo Midstream late last year, which will provide a backbone to support future APC Wolfcamp growth that Chuck will talk about momentarily. Beyond the capital that WES invests, through 2014, the MLPs have returned more than $3 billion of cash to APC since the IPO of WES, back in 2008. You can see, in the graphic at the bottom of the page, that this has been through asset sales and distributions that have increased to APC over time.

And last year, through the first sale by APC of some of its position in WGP securities, of which we still own over 88%. And as Al mentioned, importantly, APC owns more than $12 billion of marketable securities, primarily in WGP and some in WES. That, today, is more than a quarter of APC's entire market cap, so it is indeed substantial value, and the model is poised to continue well into the future. So turn to the next slide 17 here, we think the appropriate way to look at the trading value of APC's EMP business is to exclude the WGP and WES value. We've done that on this slide.

Now, the analysis was originally performed by Heikkinen Energy Advisors, and it considered the impact of hedges as part of the enterprise value, and not EBITDA, for evaluation purposes. As you can see, Anadarko's unhedged EBITDA multiple is about the same as the median of the large-cap universe. However, when you appropriately excluded WES and WGP from the calculation, on the far right, Anadarko's trading at more than a one turn discount to its peers, on an apples to apples basis.

So clearly, as you can see on this slide, and the earlier one that showed leverage, both pre and after excluding WES and WGP, in order to properly consider APC relative to its peers, the effects of the successful MLP model need to be removed from the consolidated number, both from an equity and a debt perspective, to get a clear view of how Anadarko compares on an apples to apples basis. In summary, financial discipline has been one of the planks of our strategy for several years. We've strengthened our balance sheet through disciplined capital management for several years, across various market cycles.

We remain committed to preserving that strength and maintaining our solidly investment grade credit ratings. And we have the liquidity and the flexibility to manage through uncertainties like the industry is currently facing. We're going to continue to seek opportunities to enhance value, including evaluating strategic opportunities when they are available to us. And we're going to continue to focus on managing the Company's balance sheet in a responsible and long-term way. Chuck Meloy is here next, to talk about our US onshore business, and I'll be available at the end of the call to answer any questions on my slides. Chuck?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Thank you, Bob. Listed are the key elements of our 2015 operations play book. I'm very proud of the 2014 results, and our drive to continuously improve all elements of our business. And our safety record reflects our commitments to doing it right. Over the last few years, based upon our

exploration success in the US shales, we built a very large production base in quality assets. This year, we intend to wring the value out of that base production, by leveraging our field engineering teams, our operations technologies, and our integrated business approach.

We maintain the ability to adjust our activities to the commodity markets, either up or down. One of our significant deliverables this year will be to build a foundation for the Wolfcamp to be a major growth -- for Anadarko into the future. I've also listed some of the key elements and competitive advantages of our integrated business approach. And we will speak to most of these, as we move through this presentation. During this portion of the cycle, it has been my experience that flexibility is at a premium. We will be reducing our rig count by 40% during 2015, as compared to the 2014 activities.

As we enter 2015, our contract flexibility shown on the graph will provide us with the capability to accomplish this goal. In addition, we will also defer approximately 125 completions, as Al mentioned. This will leave us with roughly 420 to 440 drilled, but not completed, wells when we exit 2015. This inventory of drilled but not completed wells offers us an opportunity to flex our program, commensurate with the service and commodity markets throughout the year. Our CapEx allocation will continue to be Wattenberg-centric, investing roughly $1.8 billion of the total $3.8 billion in the Wattenberg field.

Although we will invest at a reduced level in the Eagle Ford and the Wolfcamp, as compared to 2014, we will still meet our strategic objectives for these particular assets. We will round out the program with investments in East Texas, midstream and exploration. As I mentioned, the Wattenberg field continues to be one of the more attractive investments in our portfolio, due to its royalty advantage, economies of scale, infrastructure advantage, and a large, high-quality inventory. A brief second to do a shout out, for our team has given this asset a growth rate of greater than 15,000 barrels a quarter during 2014. And as you know, most of that growth was liquids.

This year, we plan to drill roughly 280 Company-operated wells, while averaging eight to nine rigs. We plan to execute about 40% of our completions in the first quarter, and will defer roughly 70 completions out of 2015. This field is a great example of CapEx efficiency, as our drilling footage per rig is about 25% greater now than in 2013, and we see the potential for additional gains in 2015. Currently, market conditions encourage ethane rejections equaling almost 25,000 barrels equivalent per day, just at Wattenberg alone. The combination of fewer rigs, deferring completions, and ethane rejection will slow the growth to roughly 25% year over year, for just the horizontal programs, while still delivering quality economics.

With our competitive infrastructure, we hold the option to flex this plan up or down, depending upon market conditions. 2014 marked the year our teams pushed ahead of the production growth, with significant infrastructure projects. They included the 300 million a day Lancaster I processing plant, expanding the NGL and oil takeaway capacity, and other significant field projects that increased our compression capacity. You can really see the benefit of these projects in the 2014 production growth, as I mentioned in the previous slide. We will follow up this year with more field-level gathering and compression facilities, an oil handling and stabilization facility, and another 300 million cubic feet per day at Lancaster II gas plant.

This should give us the head room on capacity, should the market conditions suggest we should increase our drilling and/or our completion base. Collectively, all of these projects have put us in a really good spot to deliver the immense value this field has to offer. So let's move on to the Delaware Basin. The title of the slide is reflective of what we see in the Delaware. It's big. A game changing asset, with over 1 billion net resource potential added to our corporate mid-cycle portfolio bucket. Our sales and industry have aggressively delineated this play, with approximately 160 rigs running in the basin last year, the lion's share of which were directed at the Wolfcamp.

With over 1 billion barrels net resource of potential, our job this year is to use our proven approach to set this asset up for tremendous growth in the future. We have learned a considerable amount about the Wolfcamp over the last 12 months or so, and feel comfortable with at least four of the benches offering commercial value. We see EURs increasing from East to West, but liquid recoveries increasing from West to East. The early production data implies that there will be 1 million barrel EUR levels in the field. Truly amazing. We will continue to optimize our completions, as we have seen rather dramatic improvements, as we fine-tune the Wolfcamp recipe, while conservatively flowing these wells.

We're very fortunate to have a 600,000 gross acreage position, right in the heart of this oil-rich play, with very low entry cost. We have benefited from our extensive operating infrastructure position in the basin, and as you can see in the graphic, the gathering production and process facilities almost overlap all of our acreage position, which provide a significant commercial advantage. You can trace those facilities from Northwest, where

the Nuevo plant is located, extensive pipeline infrastructure, shown in red, which is the gas gathering system, all the way down to the Southeast corner, where we have our [bonus] plant.

We've also established connectivity with key markets, which should deliver the best available net-backs for our products. Having this footprint, this early in the game, will deliver significant operational synergies, and will enable the project to deliver its maximum value potential. You might recognize this approach from our very successful execution model that we've done in the Wattenberg field. As I mentioned, with multiple ventures in the Wolfcamp, with 1 billion barrels net resources, and a great head start of enabling infrastructure, we will be pressing ahead with the design and implementation of our field development plan.

Our drilling focus will be on gathering critical information, while meeting our leasehold earning commitments. We should average roughly six rigs for 2015. Our current long-range plan is to have multiple staggered laterals in two to four benches, with high intensity completion technology. We're still working through the early time data, and the production information from our delineation spacing data, and will likely make some decisions on the ultimate development plan during the next 12 to 18 months. With a lot of work to do -- we still have a lot of work to do. But I'm very excited about what this asset will mean to Anadarko, for a long time to come.

Moving on to the Eagle Ford. We recently reached a remarkable production milestone of 0.25 million gross processed barrels of oil equivalent per day, including over 100,000 barrels of oil equivalent per day. This puts us among the lead producers in the southwestern portion of the play. This growth was achieved in just five years of field life, truly a remarkable accomplishment. A few of the other accomplishments of our Eagle Ford team was a record low average drilling cost of $89 a foot in the fourth quarter of 2014. A record well in 4.5 days, from spud to rig release.

We fracked over 6,700 stages during the year. Recycled almost 1 million barrels of water, and installed over 300 artificial [lift] installations. These milestones, and many others, deserve a shout out to our team, the service providers that have worked tirelessly to move this asset forward. Great job, folks. Improvements in completion technology designs have continued to improve the CapEx efficiency of the wells, as you can see the value uplift from 2013 to 2014, on a constant price basis.

Our 2015 program will be roughly half of the 2014 program, focusing on taking advantage of the infrastructure, efficiencies and scale we've created. This map, shown on the slide, illustrates the extensive infrastructure we have deployed in our Eagle Ford assets. You've heard me mention the criticality of infrastructure with each asset, so I want to emphasize the reason we put so much focus on it. A robust infrastructure position reduces [disrupt] traffic and its associated costs, spills, flaring, emissions and overall lifecycle cost, while increasing the safety performance, the runtime, the market flexibility, and the underlying asset value.

Our Eagle Ford position, and the many milestones I mentioned earlier, are a testimony to the integrated business approach we discussed at the beginning of this presentation. So in summary, we put together a top-tier portfolio, including marquee assets in three major horizontal oil shale plays, and two horizontal shale gas plays. We focused on growing our liquids production, and we have really seen the benefit in our realizations on improving our capital efficiency and lifted cost through the last few years. As Al mentioned, 2014 was a landmark year for our business.

It was led by the horizontal Wattenberg program. You can see the amazing growth we generated in 2014 in the table shown here. In 2015, we're going to align our CapEx program with the market realities, grow our liquids year over year while letting our gas volumes decline, all the while holding the options to flex up or down with actual market conditions. Clearly, the growth will come from the three key oily horizontal plays we discussed in detail today. And the hard work of all of our teams, and all of our assets, as we execute our 2015 play book. Thank you for your time, and now I'll pass the podium to Jim Kleckner.

Jim Kleckner - *Anadarko Petroleum Corporation - EVP of International and Deepwater Operations*

Chuck provided a good overview of our onshore properties in the lower 48, and I'll cover operations in our international and Deepwater areas. This assets are high-margin, high-quality oil producers. And because of the commercial approach used in our exploration and development process, provide good returns at current commodity prices. Net production of over 180,000 barrels oil equivalent a day expected this year from our fields onshore in Algeria and Alaska, and the deep waters of Ghana and the Gulf of Mexico. The majority of these assets have low decline rates, low operating costs and low maintenance capital requirements.

Our expertise in project management enables us to move our exploration discoveries through appraisal and development quickly and efficiently. And as a result, we will grow our liquid volumes this year and beyond, with two new mega projects scheduled to come online in 2016. Our expectation for capital spend is $1.4 billion this year, and will be focused primarily in high-margin [uphold] properties. And we continually focus on improving performance. Whether it be drilling challenging wells, or building and operating large facilities installed in remote environments, we strive to do it safely and with care and protection of the environment. We also strive to develop these projects quickly and efficiently, to maximize value, and use benchmarking studies to measure our progress.

The independent project analysis groups provides benchmarking services, and has data on more than 1,400 development projects worldwide. 2014 data has been released from IPA. And again, our teams have delivered projects that outperform industry norms on both schedule and capital efficiency. This was accomplished on multiple fronts, and includes developing appraisal strategy that allow a rapid determination of resource size, standardizing technology and equipment that allow us to leverage inventory and skills of our employees and service providers, and strict adherence to disciplined project management.

As you can see on the bottom chart, the Lucius and Heidelberg developments will achieve first production, on average, of just six years from discovery. That is 40% faster than recent and comparative Deepwater development projects in the Gulf of Mexico. There are several projects in various stages of development, and I will go into more detail about them in the upcoming slides. In each case, we're building on previous experience to evaluate resources more efficiently, and utilize development solutions that have proven track records. As you are aware, Lucius came online in January, and is ramping up to full capacity over the next several weeks.

Development drilling continues at our Caesar/Tonga fields, where we have just completed our fifth well, and it is online and flowing. And we are moving towards partnership approval of the second phase of field development, which envisions another four to five wells. These wells are tied back subsea to the Constitution Spar. Infrastructure is in place, so development costs of this space, too, would be relatively low. Heidelberg is the twin to the Lucius spar hole and topside facility, and is a testament to staying with proven design concepts and service providers to eliminate execution risk.

Our experience in Deepwater development, and construction and operations of large facilities, are a good fit for the challenges of the LNG project in Mozambique. We have a history of delivering high-value growth opportunities across the globe, with projects that deliver significant volumes and cash flow. As you can see from the projects highlighted in the upper right, growth has been consistent, and will be so for many years to come. This represents projects in various stages of development, and does not include potential growth from recent discoveries like Shenandoah or Paon or Phobos. We continue to look for ways to accelerate value and leverage our capital investments.

And at Lucius and Heidelberg, value was brought forward by obtaining a carry and development capital, for exchange of working interest. And in Mozambique, we sold the 10% working interest, which collectively accelerated over $3.5 billion of value. I think this is a great illustration of the cash flow generated from our commercial approach to development, and our track record of delivering mega-projects on schedule and within budget. As I mentioned, we achieved first production at Lucius just six weeks ago. This is three years from sanction, and five years from discovery.

And I'd like to congratulate all of our people, and the providers that enabled this project to go forward successfully. It's a job very, very well done. Today, Lucius is flowing at about 35,000 barrels a day, at 43 million cubic feet a day, and will ramp to over 80,000 barrels a day in the next several weeks. The field has six additional wells, which have been drilled, five of which have been completed and tested at rates between 10,000 and 15,000 barrels a day. The wells are completed in the Pliocene with great porosities and permeabilities, and as such, they a very minimal draw down. In fact, they of some of the largest productivity indexes that we've seen through many of our wells in the Gulf of Mexico.

Now, having the facility, and the gas and the oil export lines, gives us first mover advantage in the area. And the partnership assigned process handling agreements for tie backs to the Lucius spar on the South Hadrian, Buckskin and Moccasin fields. These are great value adds, and revenue from the PHAs will recover almost twice the cost of the spar hole and the top sides. In addition, we exchanged a 7.2% working interest in the field for a capital carry of over $550 million, and that established an asset value for Anadarko's interest, at the time, of over $2.7 billion. Payout for our invested capital is anticipated in less than one year from first production.

Lucius is great asset, and will generate substantial free cash flow for the years to come. Heidelberg is located in the Green Canyon area south of Caesar/Tonga, in the Constitution spar. The project is on target to deliver first oil in mid-2016, which is, again, only three years from sanction. Construction of the spar hull will begin at the Technip [Bjorn] in Pori, Finland, in late 2012. The hull was transported to Ingleside, Texas, where it is being readied for tow-out and site installation in the coming months. The top sides are being fabricated at Kiewit Offshore Services, at Ingleside, as well, and are about 75% complete. And they are scheduled for installation atop the spar hull later this year.

Development drilling began last year, and we currently have two rigs in the field that will drill a total of six wells in the subsoil Pliocene. And similar to Lucius, we were able to leverage the quality of this project with our higher working interest to obtain capital carry. In exchange for 12 3/4 working interest with Marubeni provided the capital carry of about $860 million. And this established an asset value for Anadarko's interest at the time of $3 billion. Now moving to West Africa, the Jubilee field in Ghana continues to produce at over 100,000 barrels a day. The field has surpassed 125 million barrels cumulative production since starting in 2010.

Gas export to onshore markets in Ghana commenced last quarter, which will enable higher oil production rates in the future, as the producing GR is reduced. We've seen recent production rates as high as 110,000 barrels of oil a day, after successful well asset jobs earlier this year. Work is also underway on debottlenecking projects to reduce gas constraints, and design work is progressing for expanding oil throughput, as expected to further with feed studies in the first half of this year. Jubilee partners plan to submit full field development plans for the Mahogany, Teak and Akasa discoveries to the government of Ghana, at mid-part of this year, as well.

Now adjacent to the Jubilee field are the Tweneboa and Enyenra and Ntomme fields. And these refer to the TEN developments, and like Jubilee, we will use an FPSO size for 80,000 barrels a day to bring this field online in 2016. TEN is expected to bring similar high-margin premium crude oil, like Jubilee. The project has reached the halfway milestone at the end of last year, as achieving cost and schedule expectations. The first 10 wells have been drilled, with results meeting expectations. The installations of subsea infrastructure equipment is expected to begin in midyear.

Algeria, as a core asset in the portfolio, continues to be a strong performer. We initiated production in 1998, and should surpass 2 billion barrels of fuel to production later this year. Our Algerian assets are the largest free cash flow producing assets in the Company, and last year, generated over $1.8 billion of EBITDA. The net production records we set last quarter, as El Merk reached plateau rates, and we exited the year producing approximately 400,000 barrels a day gross production from HBNS, Aru and El Merk fields.

All these fields are characterized by high quality reservoirs, with low operating costs and low maintenance capital requirements. They are outstanding assets. We have delivered three world-class projects in the middle of the Sahara desert, with our El Merk project coming in on budget, with production reserves meeting expectations. Mozambique is a phenomenal value creation opportunity that will create a world-class competitive global LNG supply source. With over 1 million acres, we have discovered 75 Tcf of gross recoverable resources. And our approach is to build an initial development of two LNG trains at 10 million tonnes per annum, and make the facility scalable to over 50 million tonnes per annum.

Several factors give this project cost advantage against other developments. First, the gas is close to shore. Second, there is a natural protected harbor. Third, the reservoir is extremely high-quality. We've had wells out here tested over 100 million cubic feet a day, with excellent connectivity to the main reservoir bodies, allowing us to drill fewer wells. Because the reservoir performance is so good, we are not anticipating the need for offshore compression, and we are progressing a subsea to shore development, which will enable enormous savings, not having to install an offshore platform for compression.

And fourth is our East African location. We've got great proximity to premium Asian markets, which is an important cost consideration, when you think about delivered cost of LNG. We're working with our partnerships, and the government of Mozambique, to bring the first train of LNG to market in 2019. Over the past year, we have advanced key aspects of the project to the point where we have created an ability to begin construction later in 2015. The pace of this is now dependent on getting the remaining government approvals and agreements that are needed. We have made great progress.

Enough reserves have been certified to justify an initial two LNG trains. A decree law was gazetted, which was a very strong signal from the Mozambican government of support for the development of an LNG industry. Competitive feeds for both onshore liquefaction and offshore

gathering systems are now complete, and the [contractor] decision is pending. We have strong support from the Pacific markets, with over 8 million tonnes per annum of non-binding HOAs. And finally, we have received indications of funding commitment for 60% of the required project financing.

So our exploration success, coupled with project management expertise, has created a pipeline of high-quality investment opportunities, through being developed, and will deliver long-life, high-margin oil production for years to come. We have seen good success in the past in the Jubilee, Caesar/Tonga and El Merk fields, and are realizing the ramp-up of production volumes from the Lucius development. We're currently bringing our expertise, our energy and our focus to bear again on the Heidelberg and in Mozambique projects, and are working with our exploration teams to move the next generation of opportunities through appraisal and commercialization.

I'll be happy to take questions later on, but at this point, I will turn it over to Bob Daniels.

Bob Daniels - *Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

Thanks, Jim, and good morning, everyone. I've talked before about our proven exploration strategy that has yielded an impressive five-year track record. We've delivered over 65% Deepwater success. That's about a 50% uplift over the industry, during that time frame. And over 4 billion barrels of oil equivalent of net discovered resources for the Company. Our strategy is very consistent. We focus on our strengths, as I've mentioned before, Deepwater globally, [plastic] systems that we can take advantage of our seismic imaging expertise.

We base all our decisions on our portfolio, where our opportunities are evaluated against each other. Our risk assessment is very rigorous and consistent, and we're always focused on value creation. We tend to get in early, at a low cost. Examples would be Ghana, Mozambique, some of our Gulf of Mexico plays, now Colombia. We optimize our working interest, and use commercial leverage very effectively. You'll see more of this later. But this mitigates risk, with manages our capital exposure and enhances our returns.

I can't say enough about the talented oil finder we have here at Anadarko. We have a culture of creativity, built on a petroleum system foundation. And we use the appropriate technology application to solve problems. That's the key thing. We look at what problems we have, and what technologies are available to us, and utilize that. So we discover and we advance our discoveries very quickly, as Jim mentioned. The track record of success goes back farther than five years, though. Since 2007, we've had at least one of the top 10 Deepwater discoveries in the world each year, something we're extremely proud of, and speaks to the talent and dedication of our exploration team.

But a successful track record is only significant if it yields value. Let's look at our 10 year value creation scorecard. Since 2005, we have invested $10 billion of capital in exploration. That has yielded 6.5 billion barrels of oil equivalent of net discovered resources. This has paid for our exploration program, and returned cash to Anadarko. Meanwhile, we have monetized part of that for $13 billion, and that's what has paid for our exploration program.

That's -- we did that through farm-outs, sold interests, or sold out. And yet, we retained over 5 billion barrels of oil equivalent resources for the Company, of which 250,000 barrels of oil equivalent per day is producing now. And the value creation continued in 2014, with discoveries in Mozambique. Once we discover things, we drive value realization through successful appraising, as shown in the chart. Or best-in-class developments, such as what Jim was talking about at Lucius, where we had first oil in 2014, and the Heidelberg 10 coming on in 2016, the advancement in Mozambique.

Or value realizing monetization, such as what we did at Mozambique, where we sold 10% gross interest. Or our non-operated discovery veto in the Gulf of Mexico. This is what we do, and it's a great example of driving value creation and creating tremendous optionality for Anadarko. It's also a great measure of the success of our strategy. Consistent with this, we advanced a lot of value-adding activities in 2014, all very consistent with our strategy. We leveraged our success. We utilized about $200 million of funding other people's money through farm-outs, again managing our capital, mitigating our risk and enhancing our portfolio value.

We closed over $3 billion of monetizations, as mentioned before. The non-operative veto prospect in the Gulf of Mexico and Mozambique. We delivered 200 million barrels of net discovered resources to the Company. We doubled our acreage position in Deepwater Colombia, exposing us

to numerous play types and significant potential. We had more exploration success at Tubarao Tigre in Mozambique. We had a successful appraisal in Mozambique, and the Gulf of Mexico at Shenandoah, and Cote d'Ivoire at the Paon discovery. And we're starting fast in 2015.

We're drilling in the Gulf of Mexico at our Yeti prospect, a Miocene subsalt target, south of Big Foot. In Colombia, we've spud our first play opening opportunity at Kronos, and are drilling as we speak. And in Mozambique, we successfully completed our Deepwater exploration program. All of our discoveries have been appraised, and we've handed over the entire Deepwater to our operations team. This truly is an active start to what looks to be an exciting 2015 exploration program. Let's look in the details of the 2015 international and Deepwater investment plans.

If you look at the bar chart on the right, we are anticipating about $600 million of capital to be invested in exploration in 2015. About 80% of that will be focused on drilling activities, and the rest will be G&G, which will be large 3-Ds for future opportunities. Our drilling will be focused in Deepwater Americas and Africa. The majority of the wells will be improvement plays, with running room, such as Gulf of Mexico, Cote d'Ivoire or East Africa. And we've got two wells in Colombia, a frontier Deepwater basin, where we have multiple play types and 16 million acres controlled. We also will be acquiring seismic data in New Zealand, and on our new acreage in Colombia, which will set us up for the future.

So the $600 million of investment sets us up for the future with the 3-Ds, allows for 9 to 12 gross exploration and appraisal wells, and targets over 700 million barrels of oil equivalent mean net discovered resources, so a very significant program. Let's look at some more details of a couple of our focus areas, starting in the Deepwater Gulf of Mexico. We're excited about the advancement of Shenandoah. We pushed down dip on Shenandoah-3, searching for the oil/water contact, looking for reservoir continuity and quality, and to get a core in the down dip portions of the reservoir.

This was a very successful appraisal well. In 2015, we will drill Northwest of the Shenandoah number 2 well, with our Shenandoah-4. This will be to extend the field to the West, and up dip, and to obtain a core in the oil lag for our development plannings. Meanwhile, we're also drilling, as I mentioned, at Yeti, which is a Miocene three-way located beneath salt, in a very good neighborhood that we understand. You can see Big Foot to the North, which is producing, and Cascade to the South. And of course, you might remember that we were involved in the original Big Foot discovery, prior to monetizing that asset.

We will follow this up with a prospect called Thorvald in the Gulf of Mexico, again, a subsalt three-way. We also have, in the eastern Gulf of Mexico, a prospect called Opal, an unconfined Miocene fan play, which could be a play opener for the industry. And we have a significant position out there. And then also, we have potential appraisal work at Phobos this year, to understand what we have, and to plan for potential development solutions. Turning to the international, Deepwater exploration, in Cote d'Ivoire, we're advancing toward commerciality at our Paon discovery.

We drilled two wells last year that were very successful. And in 2015, we're planning an appraisal well and a DST, which will test for deliver-ability of the reservoir system, and we will have pressure monitoring in the existing wells, to look for continuity. Colombia, as I mentioned, we have drilling underway. Kronos, which is in the southern portion of our acreage position, is a large three-way structure, and that's drilling as we speak. We will move, after that, to Calasu, a large four-way in the northern portion of the Fuerte blocks, which is a multi-zone four-way structure. We have top-set that, and we will finish as soon as we're done with Kronos.

In the Grand Col area to the north and east of the drilling areas, we have a large 3-D that we're going to be acquiring this year, over the 8 million acres that we acquired recently. We're also going to be drilling in Kenya at Mlima. We have a large four-way structure that is pursuing known reservoirs, up dip, in a proven petroleum system. And Mozambique, we finished our appraisal work at Tubarao Tigre very successfully. We've always leveraged our exploration success, and 2015 is going to be no different.

We identify and capture opportunities early, and we get attractive fiscal terms. We then perform early science, creating value by developing captured ideas into high-quality projects that others would like to participate in. We leverage our reputation, and ensure win-win partnerships. We have a track record of success in value creation, for us and our partners. This has allowed us, in 2014, to bring in about $200 million of outside funding, a 25% uplift in our activity.

And it will continue in 2015, where we're looking again for $200 million in additional funding, much of which is already placed, and will lead to about a 33% uplift in our total activity. And as I said, this is nothing new. It is built into our strategy. Since 2007, we've had just under $2 billion of

farm-out funding, which has helped manage our capital, lessen our risk profile, and significantly enhance our portfolio value. Truly a competitive advantage.

In conclusion, our track record has demonstrated the success of our strategy, the results it has delivered. And now 2015 is consistent with it, in the present environment. I'm confident that in 2015, you'll see us continued accelerating portfolio value, advancing discovers and pursuing play opening exploration. We will continue to leverage our success, whether through farm-out funding, unique access to opportunities, or preferred partnerships. And we'll continue to provide option value to Anadarko, whether to take discoveries to development, sell down, or sell out, we provide lots of options to create and enhance value.

I've shown you our internal scorecard of the value our exploration team has delivered, but here's a third-party assessment of how Anadarko's exploration has stacked up against our peers. This is from Wood Mac, September 2014, over 35 peer companies, looking at the exploration spend and exploration resources delivered, and the value created. And you can see, number one is Anadarko, against the total peer group. We're very proud of that. So to sum up, we believe in our strategy. It has delivered a significant value. And we're confident that exploration will continue to create value and optionality for Anadarko in 2015 and beyond.

And with that, let me turn it over to Al.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Thanks, Bob. And I think we would, at this point, like to turn it to Q&A. And so I believe the first person up is Doug.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions)

Doug Leggate, Bank of America Merrill Lynch.

Doug Leggate - *BofA Merrill Lynch - Analyst*

Hi, good morning, Al, can you hear me now?

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Yes, thanks, Doug.

Doug Leggate - *BofA Merrill Lynch - Analyst*

Excellent, thank you. A couple of quick questions, Al, please. Thanks for all the detail this morning.

Could you be clear on the divestment? In your prepared remarks, has the enhanced oil recovery already been sold, in terms of the volumes? Or can you frame for us, what was the likely timing? And maybe some range of proceeds?

And your answer, if I may, there was some speculation yesterday on the wires that East Texas may be for sale, also. So if you could give us a broad idea about how you're thinking about the portfolio management generally? And I've got a follow-up, please

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

I'm going to actually, if I can, have Bob Gwin address some of your question, and tell you that, while we haven't targeted any other assets, particularly East Texas, I think, as you know, from having watched us for several years, we always consider everything in our portfolio. And everything that's in there is something we would manage.

But there is a few things that we would always consider. And there's probably some questions around some things we have, and whether they are for sale or not. But we're pretty clear, in the sense that anything we've got, if we think we've got a pretty good offer on the table from them, we'd consider it.

So as it relates to the assets that we announced this morning, Bob, do you want to address that?

Bob Gwin - *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Yes, I will touch on that. Doug, without going into a specific number on EOR, I think you can think in terms of that $700 million plus number that we identified, year to date, as representing EOR. We've entered into an agreement that we would expect to close near the end of this quarter. And obviously, we feel good that taking that money, and redeploying it into the 2015 capital budget, to support -- in excess of our cash flow, to support the aggregate spending level, is the right way to spend the money.

Exiting the EOR, in effect, and redeploying into mid-cycle, as you saw one of Al's slides, primarily the Wolfcamp, as well as our exploration program, clearly gives us better growth assets, going forward in an asset that historically hasn't provide much free cash flow. And we think we've achieved full value in the current oil price environment, so we're pretty happy with that sale.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

And Doug, let me add that the 2015 volumes we've given you do not assume anything for EOR.

Bob Gwin - *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Yes, we have backed that out. And there's a reconciliation in the earnings release, to talk about what we mean from -- or in the announcement this morning -- to talk about what we mean when we say divestiture adjust. So there's a pretty good reconciliation in there.

Doug Leggate - *BofA Merrill Lynch - Analyst*

Okay. I appreciate the answer. My follow-up is really, if I heard you correctly, your CapEx budget does not assume any service cost reductions. I guess I understand why you are framing it that way.

But can you provide some order of magnitude, as to what you believe might be possible, in terms of your activity? And in the context of your cash flow, do you expect to live within cash flow this year? And I'll leave it there. Thank you.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Yes, you bet. And you are right, in terms of the way you characterized my comment. We have put into our plan those things that we have realized in the first couple of months of the year. Maybe, unlike others, we have not projected what we think service cost savings could be through the course of the year, thinking that's really going to have more of a full-year impact in 2016.

If I can, Chuck will walk you through some of those types of things we're seeing. But what we're trying to do there is simply not be overly aggressive, with respect to how much of our capital intensity could come down, primarily because we don't intend to complete all the wells we are drilling.

I think I made reference to the fact we think we ran125 completions that we pushed off, until such time that service costs sync up with the commodity environment that we're in. I think that's the right way for us to think about running the railroad.

I think it's the right way to create value, and not pursue growth, where we don't have attractive wellhead margins. And I think it's the best thing for us to do in this environment. We're also trying to just be pretty conservative about what kind of cost -- or contractions in costs -- we may see from the service sector, without getting too ahead of ourselves.

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Doug, this is Chuck. Al pretty much summed it up. We've [added] included what we've captured to date, and -- in our numbers. So that is something we can put in the bag.

The opportunity, I think, still exists to go deeper into the cost-cutting mode. But is very dependent upon how our service providers react to this environment, as well as how we manage our field efficiencies, and those type of things.

So we're working very hard with our providers. We see opportunity. When we capture it, we will certainly take good use of it. Either redeploy it, or put it into the savings bucket for redeployment later.

My sense is that, with our program, the biggest opportunities lie in the completion space, but we'll have to just see how this market plays out. If history is any indicator of how things happen during these environments, there's still some room, but how much is yet to be determined.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

And Doug, your question about free cash flow and CapEx syncing up, depending upon your price deck, our assessment is, is that with the cash associated with the sale of the assets that we announced this morning, we should be about cash flow neutral, with respect to the CapEx plan for the year. But obviously, we could have a lot of improvement on the CapEx side, related to service cost contractions. And we could have some surprises, with respect to the cash flows related to the commodity deck. So our assumption is, is that we should be pretty much flat with CapEx to cash plus cash flow.

Doug Leggate - *BofA Merrill Lynch - Analyst*

That's what it looks like (inaudible) as well. Thanks very much, Al. Appreciate it.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

You bet.

Operator

Brian Singer, Goldman Sachs.

Brian Singer - *Goldman Sachs - Analyst*

Thank you, good morning.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Hi, Brian.

Brian Singer - *Goldman Sachs - Analyst*

In slide 27, you referenced how improved completion designs have doubled the value in the Eagle Ford shale, year on year, in 2014. And I wondered if you could talk to, not just in the Eagle Ford, but the entire shale portfolio, how 2015 completions would be different than 2014? And the upside to value you see, year on year, before considering lower services costs?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Yes, Brian, great question. This is Chuck. We've continued to experiment throughout our portfolio, in the various oily assets, particularly, with different completion design, same concentrations, stage spacing, cluster spacing, pump rates. You name it, we've run experiments on it. And we continue to fine-tune the recipes for each of these plays.

And particularly in the Eagle Ford, we've seen the benefit of our spacing tests, which we have -- I think we have come to right-size our spacing, depending upon which portion of the field you are in, which is certainly part of the improvement. We've increased our sand concentrations, which is certainly part of the improvement.

And there is other little things that have continued to increase the value of it. Such as reducing the amount of water, sourcing the water in a better way, really having water available for our frack crews, so that they can pump continuously over a long period of time, which saves the system a lot of money.

So it's a combination of a lot of different things. The same thing happens in the Wolfcamp, in Wattenberg, where first and foremost, we're right-sizing the spacing, and them we are right-sizing the recipe.

Brian Singer - *Goldman Sachs - Analyst*

And so, in the Eagle Ford, if you double the value in 2015, is that -- in 2014, can 2015 be another double? Or can it be 50%? Or can you provide some perspective as to the trajectory of we're on from a value -- incremental value perspective?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Brian, it's hard to speculate on that. We have some very creative engineers and scientists working on these problems, so I certainly believe there's upside in all of this. To the extent -- what the extent is, I'm not certain.

I would just look at our track record of continuous improvement as something that we hold dear at Anadarko, and work on every day, as indications that we're going to find it. If it's there, we'll find it. And then we'll quickly adopt it into our programs. And I am hopeful that we will continue to see that kind of improvement.

Brian Singer - *Goldman Sachs - Analyst*

Great, thanks. And my follow-up is on Mozambique. Can you remind us what your current thoughts are on the overall budget and startup date?

You mentioned, in slide 40, the pace will be dictated by government approval. And I wondered, post the decree law, if you could provide key milestones on that front that are needed to keep startup at 2019, or whenever you think is realistic?

Jim Kleckner - *Anadarko Petroleum Corporation - EVP of International and Deepwater Operations*

Okay. Yes, let me just outline a few of the requirements that we're working on this year, that we consider to be milestone activities with the government.

One is the final licensing approval of the environmental impact assessment, and the relocation action plan. We are currently working those, and anticipate a response by midyear. The other modifications are to some of the contract terms incorporate the requirements for LNG, and our EPCC contract. And then, as well as gas dedication agreements that we'll need for the government processing of their volumes for the LNG liquification plant.

So those are the primary agreements that we need, moving forward. We haven't finalized evaluations of the EPCC contracts. So we're currently evaluating those. But I would think our pre-feed estimate ranges, for roughly $10 billion of onshore liquification, and $5 billion for offshore development, are still valid estimates of the costs forward.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

If I could add something to that, to put it in perspective, relative to our financial position, and the equity funding requirements associated with the project. If you think in terms of the $15 billion, roughly, that Jim talked about, and I'll use rough math.

You saw on one of his slides, he talked about two-thirds gearing to that -- from a project financing perspective. It leaves around $5 billion of aggregate equity investment, across the ownership group.

Our position, following the sell-down last year, is about one-quarter of that, a little more than one-quarter. Roughly, that's $1.25 billion of equity, net to our interest. And as you may recall, we talked previously about having roughly $1 billion invested in the project, and receiving over $2.1 billion of after-tax proceeds from the sell-down.

So in many ways, we feel like we have de-risked the project, from a financial standpoint, reimbursing ourselves for the cost to date, and then having enough equity, or enough proceeds from that equity sale, left over to fund our equity share, going forward. So we don't anticipate that any equity requirements -- equity funding requirements associated with Mozambique will change the adequacy of our capital to apply to the rest of our portfolio, going forward.

So we feel that, from a macro standpoint, this project is essentially funded. And if we can get things moving forward properly during this year, we are well positioned to fund this without it affecting the rest of our business, or putting an undue capital burden on our model.

Brian Singer - *Goldman Sachs - Analyst*

Great, thank you very much.

Operator

Subash Chandra, Guggenheim.

Subash Chandra - *Guggenheim - Analyst*

Yes, hi, good morning. Thanks for the call. I was curious, I think on slide 21, just putting out the wedges of CapEx. And that other wedge is quite small. When I look at your producing asset base, there is a lot in other.

And so I am curious what the plans are beyond 2015? Do you think these fields become sources of free cash flow? Do they get monetized?

I understand your comments on 2015 monetizations, but -- or do they play a role in decline rate management? And so what are the efforts, in those fields, in that broad category of other fields in 2015, if it's not new drilling?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Subash, this is Chuck again. Thank you for the question. The other really involves various OBO positions that we have in the Marcellus, for instance. And very small amounts of maintenance capital-type investments in some of our gas assets.

So it's generally a bucket that we put our gas assets into this year, and [Savies],Texas, which still has really good economics. So it's really just a collection of miscellaneous investments that make up the balance, primarily small investments in various gas assets.

Subash Chandra - *Guggenheim - Analyst*

Right, but when I think of the assets that they are, they are a pretty large producing base of assets. And if I think of just GNB, and some of the other fields out there, the gassier ones, as well, they all add up.

So is 2015 a year of, take a pass on those, maybe do some work -- maintenance work on the fields? And then renew growth, in a better price environment? Or are some of these fields now in the late phases, and won't see growth, and might see other ways of extracting value?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Subash, I think you pretty much hit it on the head there with, these are assets that we're going to put on the sideline for a bit, until the investment climate improves. They're fantastic assets. They are very large-scale assets.

You are well aware. Like GNB, for instance, produces over 500 million cubic feet. The Marcellus position is North of 1.5 BCF a day gross. So these are large, chunky assets that still have a considerable amount of development opportunity, when the opportunity arises.

There are all HBP, virtually HBP, and that take a very low maintenance capital requirement to keep them up and running. And we're just going to wait for a better time for these assets. They are certainly key and critical to our portfolio.

They give us a great big gas option, should gas prices improve at some point. And they are -- I think they are legacy assets -- foundational legacy assets for Anadarko. And we will continue to own them, and continue to produce them.

We're going to just wring the value out of them, work the base really hard, as I mentioned during my presentation, so that we minimize the decline rate from them, and just let the market re-equilibrate, give us an opportunity at that time, to (technical difficulty).

Subash Chandra - *Guggenheim - Analyst*

Thank you. And my follow-up is, in the Wolfcamp, you talked about spacing and some of the developments that you would be working on in 2015. I was just wondering, from the rock itself, what are some of the key unknowns? Or do you feel quite comfortable, from how good the rock looks, and its ability to deliver? And are there questions on, say, rock quality, area by area, or thermal maturities, et cetera?

Operator

Paul Sankey, Wolfe Research.

Paul Sankey - *Wolfe Research - Analyst*

Hi, good morning, everybody. You've highlighted the success of your monetization strategy. I was wondering if you expect the pace of that to continue this year, in the current price environment? Thanks.

Operator

Please stand by. We have lost audio. Please stand by.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

We are back. We lost you guys for a second there. Sorry about that.

Paul Sankey - *Wolfe Research - Analyst*

That's a relief. Did you catch my question?

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

No. We lost you in the middle, we believe, of Chuck answering the question for Subash. I don't know if you heard his answer or not.

Paul Sankey - *Wolfe Research - Analyst*

We got nothing. So I will just remind everyone, I was just asking simply, you've been very successful in monetizing assets over the past years. I wondered if you can really maintain that pace, in the current oil price and gas price environment? Thanks.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Paul, this is Al. Bob Gwin and I will tackle that together.

I think our track record of trying to be proactive with portfolio management will continue, even in an environment maybe that doesn't look as attractive. We still have a lot of assets, I think, that could, in fact, work its way into the monetization process this year. And specifically, I will let Bob talk a little bit more, but I think our track record is one where we have worked this pretty hard, and we will continue to work it pretty hard.

Bob Gwin - *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Yes, the only thing I would add is that, as you would expect, we have a list of assets, as we come into the year. We have a variety of assets that, over time, have a very strong return potential, and very good economics.

They just may not be attracting capital within our portfolio, going forward. And so we're going to continue to investigate the market environment for selling those assets.

If we don't think there is value there, we don't need to sell the assets. We don't need to move them. And we could certainly have them ready to go when commodity prices improve.

Some things we do, obviously, control, like our large position in WGP. We have -- we're going to continue, of course, to drop assets to Western Gas Partners, over time, which will continue to bring funds back to Anadarko. We're going to be receiving distributions and sale process.

We feel like, from a macro standpoint, cash flowing into Anadarko is going to be available. And then as Bob talked about, working on farm-downs, and these are monetizations, as well.

Working on bringing in partners in our exploration portfolio. And when we take things to development, finding oil, global oil, is something that is in demand. And I think there's always going to be a market for it. It just comes down to price, based upon the commodity price outlook.

So it's a key part of the strategy, and we'll execute as best we can during this environment. And our degree of ultimate activity will be based, really, upon what we find in the market when we are out there.

Paul Sankey - *Wolfe Research - Analyst*

Great, thanks. And if I could just push through into 2016, can you talk a little bit about how you might handle 2016, if we were still at, let's say, $60 Brent, and $50 TI? I hear that you are going to continue to push on with monetizations, as best you can. But how should we think about where you would take CapEx alone, for what you said about lower service costs not really being in your 2015 numbers? Thanks.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Yes, I think, Paul, the best way to consider that is, when we see the service cost sync up to the commodity environment that we're in, we will go back into an environment where we're willing to grow. As long as service costs are out of sync with the commodity environment, we're going to continue to look for ways to preserve value, and preserve another day when growth becomes an objective again.

If we are right where we are a year from now, and let's just say, ceteris paribus, to everything that we know today is again going to happen in 2016, I would imagine that we'll see a lot of the same comments coming from us in 2016 that we're talking about today. We just don't see any interest, from our standpoint as a management team, to show substantial growth, or much growth at all, into an environment where the wellhead economics don't support it.

Paul Sankey - *Wolfe Research - Analyst*

Helpful, thank you. And I appreciate the Latin, thanks.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Thank you.

Operator

(Operator Instructions)

Charles Meade, Johnson Rice.

Charles Meade - *Johnson Rice & Company - Analyst*

Good morning, everyone there. If I could ask two questions. I think both of these are follow-ups. Specifically in Colombia -- and I think this gets to the divestiture question -- what is the success leg look like in 2015, if you have a discovery with either of these first two, Calasu or Kronos. I

s that a -- on the success leg, would that be a divestiture candidate in late 2015? Or is it really the kind of thing that you would want to do more drilling, and have a better idea. Because it looks like you have a bunch of prospects there, and we should be more thinking about that as maybe a 2016 candidate?

Bob Daniels - *Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

Charles, Bob. Really, we need to get the wells down, and see what we have. But our track record has been, we find something, and we appraise it, and figure out what it means to Anadarko. That is the optionality that we talked about.

We want to understand what it means in our portfolio, and what the value was -- could be externally. And then we make the decisions as to whether or not we want to move forward with it, either in the development phase, or farm-down in a development, or whether we divest it all.

So I wouldn't think that you're going to see much in 2015. These -- we just started the wells, and they are going to be done midyear. So that will be the first activities, and then we're going to have to come back in, with success, to appraise and understand what we have.

And we also -- this is not a one-off position. The area we're drilling with Kronos and Calasu, that's 8 million acres. And we have multiple play types in there.

So these wells could actually tell us a lot about what else we have, and what the total potential of the blocks could be. And we would like to then evaluate what that means to Anadarko.

Charles Meade - *Johnson Rice & Company - Analyst*

Got it. So Bob, if I understand you, we ought to be expecting more of a Mozambique sell-down, where you sell down on the whole concession, rather than a Gulf of Mexico style, where you would do it on an individual find or prospect?

Bob Daniels - *Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

Yes, it's very difficult to do it on individual finds. But I think that at this point, we really need to know what we have, because we don't make any decisions ahead of time. We have to understand what it means to Anadarko, and what it would mean from a value standpoint into the market.

Charles Meade - *Johnson Rice & Company - Analyst*

Got it. And then if I could switch back to the onshore North America, and just following up a bit on the completions question, particularly in Wattenberg. And Chuck, on your slide 22, I was a little surprised to see that down in the southwest corner of your acreage position, you have a --

further into the oil leg, you have an EUR of 450, whereas -- I guess my understanding of the field is that your EURs were typically higher, as you got to the center, deeper part of the basin, where it was gassier.

So I wonder, is that a function of the 24 well [for section] spacing test you see there? Or is -- am I on the right track, to be surprised there? Or is that -- what might I be missing?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Charles, good question. The EURs that we show there are just the ones that we have seen recently. And not all the wells -- they do, in fact, increase as you get gassier. We just haven't drilled a whole lot of those wells this year.

So the one in the Southwest quarter, particularly, is an area that didn't have a whole lot of vertical development. So we've had some really nice wells this last year, in 2014.

And that was part of the reason we saw such as a huge growth in the Wattenberg field in 2014, was because these fantastic wells, and the program that we put together in 2014. So it's really not a surprise.

I think you will see variations throughout the field, but so far, so good. Everything looks really good to us.

Charles Meade - *Johnson Rice & Company - Analyst*

So -- but were they on that tighter well spacing? I guess what I am after, Chuck, is, they're -- industry is not talking a whole lot about, but there's that idea of possible constructive interference? And is that maybe what we are maybe seeing there?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Charles, the way we have put this together, these are generally on our expected well densities of about 12 wells per section. There are a few tighter well spacing tests in each one of these areas. So it's a mix. I'm not avoiding your question; it's just a mixed bag.

Charles Meade - *Johnson Rice & Company - Analyst*

No, that's great. Thank you.

Operator

Jeffrey Lambujon, Tudor, Pickering, Holt & Company.

Jeffrey Lambujon - *Tudor, Pickering, Holt & Company - Analyst*

Good morning. Thanks for taking my questions. I appreciate the detail on the US [onter ops] you all provided. In regards to the Northeast, can you give us an update on how activity there is specifically fits into this year's budget? And how you're thinking about that program, both this year and next?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Yes, Jeffrey, this is Chuck. We're going to have between zero and one rig running in the Marcellus, and probably heavier on the zero than the one, as we work through the program. Right now, we just don't see the rationale to drill into that differential in the wellhead economics.

We do have some OBO activity planned up in -- the operator is planning activities up further Northeastern Bradford County. It's very small activity, in the order of one to two rigs, as we understand it. So it's not going to be very much.

Jeffrey Lambujon - *Tudor, Pickering, Holt & Company - Analyst*

Great, thanks. And then on the Delaware EURs provided, do you have the lateral length associated with those? And maybe any updated AFE thoughts there?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Another good question. The numbers that we provided you are those for about a one-section well. Our current expenditures are pretty much associated with single-well remote delineation wells.

So the embedded costs are a little higher than what we anticipate, as we get into development mode. Right now, we're spending between $9 million and $11 million to $12 million, depending upon the specific circumstances, like roads and pipelines, and those kind of things, that are necessary to get the well online.

We see that coming down, as we get a pad orientation, and into full development mode, to the lower end of that, and even lower, possible. We have seen, and we believe there is, benefit in the longer laterals here.

There is more expense in drilling the vertical portion of these wells than we see in the Wattenberg and Eagle Ford. So the longer lateral just spreads that fixed cost over more lateral footage. And -- but we haven't done a whole lot of those, but we have certainly seen the benefit in the few we have done.

Jeffrey Lambujon - *Tudor, Pickering, Holt & Company - Analyst*

Thanks for the detail.

Operator

John Herrlin, Societe Generale.

John Herrlin - *Societe Generale - Analyst*

Hi, two quick ones. Chuck, I think you said that you were deferring 70 Wattenberg wells. What are the other 55 deferrals this year, for onshore?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Yes, John, they are split pretty much evenly between the Eagle Ford and the Permian.

John Herrlin - *Societe Generale - Analyst*

Okay, that's fine. Regarding the spending slide in your supplemental, on 21, is the Wolfcamp -- is all that value there what you would classify as mid-cycle? And that's it for me.

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

Yes, I believe so. John, if I understand your question, I think the answer is yes.

John Herrlin - *Societe Generale - Analyst*

Okay, yes, thank you.

Operator

David Heikkinen, Heikkinen Energy Advisors

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

Good morning, guys. Just thinking about 2015 services. How much had you contracted for pressure pumping and rigs this year?

And then, do those contracts roll off next year? Or just trying to think about how that rolls through this year?

Chuck Meloy - *Anadarko Petroleum Corporation - EVP of US Onshore Exploration and Production*

David, this is Chuck. The way we have contracted most of our completion simulation services was essentially on a pad-by-pad basis. We have contractors with a number of providers that give allocations, so we can essentially take our completion fleet down to zero in a very short time frame. And then we can bring them back on, with additional bidding, if necessary, or activity, as we see fit.

So we are in a really flexible spot at this point, which will give us, I think, the opportunity to realize more savings. But we'll just have to see how the market responds.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

David, could I add, I think you are familiar with what Chuck did in late 2008 and 2009, as related to our onshore activities then. And today, he has really got our onshore situation, I think, about as well prepared for changes in the environment as we could possibly hope for, by keeping all the contracts quite short.

Obviously, we're seeing more capitulation from the rig contract services being provided to date. And that's just what I see from the market.

So we are watching it, and seeing what's there. But I am very pleased with the way in which Chuck has established our contractual support for our activities onshore.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

Okay. And then, as your mega projects come online late this year, and in 2016, drives our cash flows higher. Would you invest that cash flow, or lower activity levels? Just trying to think about that push-pull of service costs that you said, and a natural level of growth from the mega projects?

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

David, if we see higher cash flows from commodity prices, and we don't see the service costs syncing up, my guess is, we will probably not put that into drilling, per se, unless we think the rate of return for the asset is pretty attractive. If we see service costs sync up in a way where we do see really attractive wellhead economics, my guess is, today, our first place to go put that capital to work would be in the Wattenberg field.

It gives us the best rate of return, both from a working interest, as well as the mineral interest perspective. And in addition to the midstream capabilities we have develop there over the last several years.

So if we actually had the ability, whether it's through either improvement in service cost, combined with commodities, to invest additionally through the year, you should anticipate that our belief today is, that would go into the Wattenberg field first.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

Okay, thanks.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

You bet.

Operator

And at this time, we have no other questions in the queue. I'd like to turn the call over to Mr. Al Walker for your final remarks.

Al Walker - *Anadarko Petroleum Corporation - Chairman, President & CEO*

Thank you, operator. Just a couple of comments here, if I can, to close up with.

The capital plan we laid out for you today, we think, as I mentioned earlier, is fairly neutral, as respect to how that spend syncs up with what we anticipate to be our cash flows, plus the sale proceeds we announced this morning. Largely, this is driven by the fact that we just see ourselves wanting to preserve value, and prepare for the day when commodity prices will sync up with the costs, and we go back and find ourselves in a growth objective.

This environment continues to support, in our mind, good investments in our intermediate and longer-cycle opportunities, as we've seen in prior cycles, particularly in the 2008-2009 period, we created a lot of option value by continuing to invest in our future. And lastly, we have talked about it all morning, and I am just going to end with it and say, you should continue to expect that our activity level, with how we manage our portfolio, will be just as intense in 2015 as it has been in any of the prior years. And we talked about what we've done for 5 years, most recently, as well as over the last 10.

And then we're going to take advantage of whatever this market gives us. And we think by actively managing that portfolio, we can create a lot of shareholder value.

So for those on the call this morning, or those listening in later, we very much appreciate it. Please don't hesitate to give John Colglazier and his staff a call. And we look forward to working with all of you through the course of the year. Thank you.

Operator

Ladies and gentlemen, this concludes your presentation. You may now disconnect, and enjoy your day.
